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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON PACIFIC GAS AND ELECTRIC COMPANY'S AND SOUTHERN CALIFORNIA EDISON COMPANY'S RESPONSES TO THE ADMINISTRATIVE LAW JUDGE'S RULING DIRECTING UTILITIES TO FILE ADDITIONAL INFORMATION PROVIDING TRANSPARENCY ON CURRENT STATIC FLEXIBLE SERVICE CONNECTION OFFERINGS

Leanne Bober,
Director of Regulatory Affairs and
Deputy General Counsel
Jennifer Baak
Senior Distribution Case Manager

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

July 8, 2025

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SUMMARY OF RECOMMENDATIONS

CalCCA[1] offers the following recommendations, organized by section and topic, for the Commission to:

- In response to section 3.1, topic 4 (FSC participant data sheets):
    - Require PG&E to submit: (1) an unredacted Data Sheet in Excel format that excludes feeder names; and (2) a separate list of affected feeders;
- In response to section 3.2, topics 1 and 2 (FSC participant selection process):
    - Require the IOUs to provide information on their existing steps for notifying the CCA supplying an FSCA candidate with generation service about the requested capacity, load limits, and partial- and full-service dates; and
    - Require the IOUs to describe their existing processes for ensuring fair and equitable treatment of FSC applicants, or propose a process to be adopted under a standardized FSCA or tariff;
- <u>In response to section 3.4, topic 3 (FSC buffer levels)</u>:
    - Require the IOUs to establish consistent standards for buffers and guidelines for leveraging equipment emergency ratings to protect against load limit violations;
- <u>In response to section 3.5, topic 2 (PG&E's lessons learned from its existing FSC)</u>:
    - Require PG&E to respond to section 3.5, topic 2(g), describing the technical criteria used to ensure that customer load under a Load Limit Letter does not exceed the emergency rating of the capacity-constrained equipment; and
    - Require PG&E and SCE to respond to section 3.5, topic 2(h), describing how choosing an FSCA impacts a customer's place in the energization queue.

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[1] Acronyms used in the Summary of Recommendations are defined in the body of this document, *California Community Choice Association's Comments on Pacific Gas and Electric Company's and Southern California Edison Company's Responses to the Administrative Law Judge's Ruling Directing Utilities to File Additional Information Providing Transparency on Current Static Flexible Service Connection Offerings*, dated July 8, 2025.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON PACIFIC GAS AND ELECTRIC COMPANY'S AND SOUTHERN CALIFORNIA EDISON COMPANY'S RESPONSES TO THE ADMINISTRATIVE LAW JUDGE'S RULING DIRECTING UTILITIES TO FILE ADDITIONAL INFORMATION PROVIDING TRANSPARENCY ON CURRENT STATIC FLEXIBLE SERVICE CONNECTION OFFERINGS

California Community Choice Association[2] (CalCCA) submits these comments pursuant to: (1) *Administrative Law Judge's Ruling Directing Utilities to File Additional Information Providing Transparency on Current Static Flexible Service Connection Offerings*,[3] dated May 22, 2025 (FSC Ruling); (2) *E-Mail Ruling Partially Granting Extension for Transparency Ruling Comment and Response*,[4] dated May 29, 2025 (FSC Extension Ruling); and (3) *E-Mail Ruling*

[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] *Administrative Law Judge's Ruling Directing Utilities to File Additional Information Providing Transparency on Current Static Flexible Service Connection Offerings*, Rulemaking (R.) 24-01-018 (May 22, 2025): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M566/K593/566593651.PDF.

[4] *E-Mail Ruling Partially Granting Extension for Transparency Ruling Comment and Response*, R.24-01-018 (May 29, 2025): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M566/K911/566911534.PDF.

Providing Clarified FSC Data Sheet Excel File,[5] dated June 3, 2025 (FSC Excel Ruling) (together, the FSC Comment Rulings).

I. INTRODUCTION

"Bridging solutions"[6] present valuable opportunities to energize customers prior to an investor-owned utility's (IOU) infrastructure upgrade to allow the delivery system to serve some or all of a customer's load. Both IOUs and non-IOUs, such as community choice aggregators (CCA), can provide bridging solutions. The FSC Ruling requests information and comments on the IOUs' existing Flexible Service Connections (FSC), defined in the FSC Ruling as "the ability to expeditiously energize new load to a utility's distribution system with variable limits on the import of electricity at certain times."[7] Specifically, the FSC Ruling seeks information on the IOUs' existing FSCs to ensure transparency regarding these arrangements and to inform future development of sample language for standardized FSC agreements (FSCA).

CalCCA appreciates the FSC Ruling's in-depth questions, and the responses provided by Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (SCE). CalCCA's comments below focus solely on the FSC Ruling topics related to: (1) information to facilitate providing generation service to customers taking service under FSC agreements; and (2) information needed to develop the standardized FSCA. Therefore, CalCCA's recommendations are limited to the IOUs' responses to: (1) section 3.1, topic 4 (FSC participant data sheets); (2) section 3.2, topics 1 and 2 (FSC participant selection process); (3) section 3.4, topic 3 (FSC buffer levels); and (4) section 3.5, topic 2 (PG&E's lessons learned from its existing FSCs).

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5 *E-Mail Ruling Providing Clarified FSC Data Sheet Excel File*, R.24-01-018 (June 3, 2025): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M567/K932/567932991.PDF.

6 Bridging solutions include improvements to the investor-owned utilities' energization processes, load flexibility options, and IOU and non-IOU owned distributed energy resources, which can enable the timely energization of loads on circuits experiencing capacity constraints.

7 FSC Ruling, Footnote 2, at 2.

CalCCA offers the following recommendations for the California Public Utilities Commission (Commission) to:

- In response to section 3.1, topic 4 (FSC participant data sheets):
  - Require PG&E to submit: (1) an unredacted FSC Participant Data Sheet (Data Sheet) in Excel format that excludes feeder names; and (2) a separate list of affected feeders;
- In response to section 3.2, topics 1 and 2 (FSC participant selection process):
  - Require the IOUs to provide information on their existing steps for notifying the CCA supplying an FSCA candidate with generation service about the requested capacity, load limits, and partial- and full-service dates; and
  - Require the IOUs to describe their existing processes for ensuring fair and equitable treatment of FSC applicants, or propose a process to be adopted under a standardized FSCA or tariff;
- <u>In response to section 3.4, topic 3 (FSC buffer levels)</u>:
  - Require the IOUs to establish consistent standards for buffers and guidelines for leveraging equipment emergency ratings to protect against load limit violations;
- <u>In response to section 3.5, topic 2 (PG&E's lessons learned from its existing FSC)</u>:
  - Require PG&E to respond to section 3.5, topic 2(g), describing the technical criteria used to ensure that customer load under a Load Limit Letter does not exceed the emergency rating of the capacity-constrained equipment; and
  - Require PG&E and SCE to respond to section 3.5, topic 2(h), describing how choosing an FSCA impacts a customer's place in the energization queue.

II. FSC RULING SECTION 3.1, TOPIC 4: PG&E SHOULD BE REQUIRED TO SUBMIT AN UNREDACTED FSC PARTICIPANT DATA SHEET IN EXCEL FORMAT WITH A SEPARATE LIST OF AFFECTED FEEDERS

The Commission should require PG&E to unredact the Data Sheet's fields with customer connected load and load limit data to allow stakeholders to provide meaningful input for developing a standardized FSCA. The Commission issued the FSC Ruling to provide transparency on current IOU static FSC offerings, stating "[t]his ruling finds that a more fulsome record is needed to inform parties' filing of Sample Language and supporting information."[8] Topic 4, section 3.1 requests information regarding customers identified as eligible for a static FSC:

> PG&E and SCE shall each provide data within the attached excel [sic] format for all customers that have been identified as eligible for a Static FSC. If additional data fields are necessary to adequately describe the LLP offerings the IOU shall append appropriate columns to the excel [sic] format.[9]

On June 6, 2025, PG&E filed public[10] and submitted confidential[11] versions of its response to this topic. The Data Sheet included in the public version redacted the following data for existing customers enrolled in its Load Limit Letter (LLL) FSC offerings: (1) customer connected load; and (2) load limit data. PG&E's basis for requesting confidential treatment of the Data Sheet was that it includes customer-specific data, which may incorporate demand, loads, names, addresses, and billing data.[12]

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8 *Id.* at 4.

9 *Id.* at 5.

10 *Pacific Gas and Electric Company's (U 39 E) Response to Question 4 in Sections 3.1 of Administrative Law Judge's Ruling Directing Utilities to File Additional Information Providing Transparency on Current Static Flexible Service Connection Offerings [Public Version]*, R.24-01-018 (June 6, 2025): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M568/K258/568258912.PDF.

11 *See Pacific Gas and Electric Company's (U 39 E) Motion for Leave to File Under Seal the Response to Question 4 in Sections 3.1 of Administrative Law Judge's Ruling Directing Utilities to File Additional Information Providing Transparency on Current Static Flexible Service Connection Offerings,* R.24-01-018 (June 6, 2025): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M568/K291/568291316.PDF.

12 *Id.* at 2.

SCE also filed a response[13] to topic 4 in section 3.1 of the FSC Ruling on June 6, 2025, including a Data Sheet in an Excel spreadsheet format, sent separately to the service list for this proceeding. Unlike PG&E, SCE did not redact data or feeder name data directly associated with each project. Instead, SCE included a separate alphabetized list of the circuits on which actual or candidate FSCA participants were located on page two of their response, without listing the associated project.[14]

Parties to this proceeding must have access to detailed FSC participant data to make informed recommendations about a standardized FSCA. CalCCA, therefore, agrees with the Environmental Defense Fund's (EDF) June 11, 2025, comments on the FSC Ruling[15] (EDF Comments) requesting that the Commission require PG&E to unredact certain data in the Data Sheet. EDF correctly points out that SCE's Data Sheet includes the same type of data that PG&E redacts, while still protecting customer confidentiality.[16] SCE achieves this by decoupling participant data from the feeder information in the Data Sheet, and instead providing a separate list of affected feeders.

EDF further reasons that the data redacted by PG&E "could show, for example, that PG&E's load limit letters are only able to serve a small fraction of a customer's requested load, and may not represent a particularly useful model for a more widespread, formalized program."[17]

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13 *Southern California Edison Company's (U 338-E) Response to Topic 4 in Section 3.1 of Administrative Law Judge's Ruling Directing Utilities to File Additional Information Providing Transparency on Current Static Flexible Service Connection Offerings,* R.24-01-018 (June 6, 2025): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M568/K294/568294761.PDF.

14 *Id.* at 2.

15 *Environmental Defense Fund Comments on Administrative Law Judges' Ruling Directing Utilities to File Additional Information Providing Transparency on Current Static Flexible Service Connection Offerings*, R.24-01-018 (June 11, 2025): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M569/K592/569592874.PDF.

16 *Id.* at 3.

17 EDF Comments, at 3.

CalCCA agrees and requests that the Commission require PG&E to submit: (1) an unredacted Data Sheet in Excel file format that excludes feeder names; and (2) a separate list of affected feeders to help parties to this proceeding make informed recommendations for sample FSCA language.

III. FSC RULING SECTION 3.2, TOPIC 4: PG&E AND SCE SHOULD BE REQUIRED TO PROVIDE TRANSPARENCY ON INFORMING CCAS ABOUT FSCA CANDIDATES AND ENSURING FSCA CANDIDATE EQUITABLE TREATMENT

The Commission should require the IOUs to provide information about their existing steps for notifying CCAs that supply generation service to FSCA candidates about the expected capacity, load limits, and partial- and full-service dates for these projects. Additionally, the IOUs should be required to describe their existing processes to ensure the fair and equitable treatment of these candidates. Neither PG&E's[18] nor SCE's[19] June 13 Responses to the FSC Ruling included information about these steps in the participant selection process. Regardless of whether the IOUs currently perform these steps, they should be included in any future standardized FSCA process.

Section 3.2, topic 4 (Providing Transparency around the Participant Selection Process for Current Static FSC Offerings) requires:

> (1) PG&E shall describe each step in the process it uses to determine an LLL.

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18 *Pacific Gas and Electric Company's (U 39 E) Response to Questions in Sections 3.2 Through 3.7 of Administrative Law Judge's Ruling Directing Utilities to File Additional Information Providing Transparency on Current Static Flexible Service Connection Offerings*, R.24-01-018 (June 13, 2025) (PG&E June 13 Response): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M569/K525/569525911.PDF.

19 *Southern California Edison Company's (U 338-E) Response to Sections 3.2 Through 3.7 in Administrative Law Judge's Ruling Directing Utilities to File Additional Information Providing Transparency on Current Static Flexible Service Connection Offerings*, R.24-01-018 (June 13, 2025) (SCE June 13 Response): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M569/K592/569592885.PDF.

> (2) SCE shall describe each step in the process that it uses to determine whether a customer is a good candidate for service under the LCMS pilot, and the criteria that are used in conjunction with that information to make the determination.

Recommendations for improving transparency in the participant selection process are discussed in more detail below.

1. A Standardized FSCA Must Include a Step for Informing CCAs About FSCA Candidates

CCAs are the default generation providers for customers within their service territories, and they must be informed about potential large new loads that are being considered for FSCAs. Such information will inform procurement of the appropriate level and timeline of generation resources necessary to supply these loads until the full load can be connected. When CCAs forecast and procure resources to supply new loads, they may be unaware of grid constraints at specific locations that could delay the full load from coming online. CCAs should be notified during the selection process about a customer's requested capacity, the anticipated partial and complete energization dates, and the agreed-upon load limits and durations for any FSC candidates within their service areas. Absent this information, CCAs risk over-procuring to serve a large load that may not fully materialize for the duration of their load limit or until long-lead time grid improvements are completed to serve the entire load. Amidst a rate affordability crisis in California, such unnecessary procurement costs should be avoided.

Many CCAs also offer load flexibility and distributed energy resource (DER) programs that could help customers manage loads under an FSCA.[20] Knowing that a customer is a candidate for an FSCA and understanding the agreement's parameters could help CCAs tailor offerings to

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[20] *See*, *e.g.*, *Richmond Advanced Energy Community Includes Virtual Power Plant and Zero Net Carbon Homes for Underserved Residents* (June 21, 2022): https://mcecleanenergy.org/mce-unveils-plans-for-virtual-power-plant-to-benefit-disadvantaged-richmond-residents-and-businesses/.

support customers with static load limits. Making CCAs aware of FSCA candidates allows them to discuss DER and load flexibility options to help manage their loads within the limits of the FSCA. CCA load flexibility options, including DER Management Systems (DERMS) programs, can help customers manage capacity beyond when grid upgrades are completed, which can also help IOUs optimize capacity to serve future loads and reduce costs for ratepayers.

2. PG&E and SCE Should be Required to Describe How They Currently Ensure Fair and Equitable Treatment of FSCA Applicants or Propose a Process for Future FSCA Candidates

SCE's and PG&E's responses do not describe how they ensure fair and equitable treatment of FSCA applicants. For example, do the IOUs prioritize customers from specific customer categories (e.g., data centers, electric vehicle charging providers, industrial customers), those who were first in the energization queue, or those with the largest loads? If more than one customer on the same feeder applies for an FSCA, how would the IOUs determine which one is selected? Given the potential expansion of FSC options in response to the expected growth of electrification, there must be a process to ensure fair, equitable, and consistent treatment of FSCA candidates across all IOUs. The Commission should require the IOUs to provide information on how they currently manage these situations or propose a process for ensuring fair and equitable treatment of FSCA candidates.

IV. FSC RULING SECTION 3.4, TOPIC 3: THE IOUS SHOULD BE REQUIRED TO ESTABLISH CONSISTENT STANDARDS FOR BUFFERS AND GUIDELINES FOR LEVERAGING EQUIPMENT EMERGENCY RATINGS

The IOUs should be required to establish consistent standards for determining load limit buffers and guidelines for leveraging equipment emergency ratings to inform the development of a future standardized FSCA. Such standards will ensure the IOUs balance the need to provide options for reducing energization times on constrained feeders with the goal of maintaining rate affordability.

Section 3.4, topic 3 of the FSC Ruling, Providing Transparency on Methodology for Computing Static FSC Profiles, requires PG&E and SCE to detail:[21]

> (a) The load buffer level they currently use for each different type of distribution infrastructure (e.g., service conductor, service transformer, primary conductor, etc.) in their FSCs.
>
> (b) The reason(s) why the load buffer level is set to this limit (i.e., the risks the utility is seeking to minimize).
>
> (c) Any internal (e.g., Greenbook) or external (e.g., IEEE C.57.91) standard(s) utilized in setting this buffer.
>
> (d) To what extent each IOU is comfortable with reducing the buffer level to allow FSCs to maximize the utilization of existing infrastructure?

In response to these subtopics, PG&E states that it uses a zero-percent load limit buffer for static FSCs equal to 100 percent of the equipment's normal rating.[22] It further explains that it sets most load limits "such that failure to comply might result in exceeding normal ratings but not emergency ratings."[23] This essentially leverages the difference between the equipment's normal and emergency ratings as an additional buffer. PG&E also states that it may increase the buffer "to ensure the safety, reliability, and asset health of its equipment."[24] SCE, on the other hand, explains that it established a five percent buffer, based on the normal rating of the most constrained equipment, but did not consider the use of emergency ratings.[25] SCE reasons that:

> Given the infancy and experimental nature of the LCMS pilot, the potential risks of grid overload if the control system technology fails to operate as intended, and the limited knowledge of power control

21 FSC Ruling, at 8.
22 PG&E June 13 Response, at 8.
23 *Ibid.*
24 *Id.* at 9.
25 SCE June 13 Response, at 6.

> system technology maturity, maintaining a 5% buffer is reasonable from a system safety perspective.[26]

CalCCA recommends that the Commission require the IOUs to establish consistent standards for buffers and guidelines for leveraging equipment emergency ratings to protect against load limit violations. CalCCA supports the development of static FSCs but encourages the Commission to ensure the IOUs balance the need to minimize energization delays by temporarily limiting loads with the potential impact of service disruptions and equipment damage caused by load limit violations. Specifically, CalCCA is concerned that some responses to load limit violations may result in "de-energizing customer load, which may also impact other customers on the same circuit."[27]

V. FSC RULING SECTION 3.5, TOPIC 2: PG&E SHOULD BE REQUIRED TO PROVIDE RESPONSES TO TOPICS 2(G) AND 2(H)

The Commission should require PG&E to submit responses to section 3.5 (Providing Transparency Around Learnings from Current FSCs), topics 2(g) and 2(h) of the FSC Ruling, which PG&E failed to provide. This information is necessary for parties to develop proposed FSCA language pertaining to the enforcement of FSC limits and to ensure future FSC offerings consider the impacts on energization queues. The FSC Ruling requires PG&E to elaborate on the following issues under section 3.5, topic 2:[28]

> (g) PG&E shall detail the technical criteria used to ensure that customer load under an LLL does not exceed the emergency rating of the capacity-constrained equipment.
>
> (h) How is a customer's place in the energization queue impacted, if at all, by choosing an FSCA?

Recommendations for each subtopic are discussed in more detail below.

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26 *Id.* at 7.
27 PG&E June 13 Response, at 12.
28 FSC Ruling, at 9.

1. Section 3.5, Topic 2(g): Technical Criteria for Equipment Emergency Ratings

PG&E states in response to topic 3(b), section 3.4 that "most Load Limits are set such that a failure to comply might result in exceeding normal ratings but not emergency ratings."[29] However, PG&E did not provide the technical criteria for determining that emergency ratings will not be exceeded as required in the FSC Ruling. Furthermore, in its response to topic 2(e) in section 3.5, PG&E describes the potential consequences of violations of load limits, stating:

> If protective equipment has been configured to trip before emergency ratings are exceeded, a violation could result in de-energizing customer load, which may also impact other customers on the same circuit.[30]

PG&E's responses confirm the potential for severe negative impacts on other customers and equipment damage or failure resulting from customer load limit violations that trip protective equipment or exceed distribution system equipment emergency ratings. By failing to provide the technical criteria it uses to ensure customers taking service under an LLL will not exceed equipment emergency ratings, PG&E deprives parties of vital information for developing standardized FSCA language. The Commission should, therefore, require PG&E to respond to this topic before parties are asked to provide sample FSCA language.

2. Section 3.5, Topic 2(h): Queue Impacts for FSC Customers

California's greenhouse gas reduction goals and technological advances are fueling the rapid growth of electrification. Interest in FSC options is likely to also grow at a time when IOUs already struggle to make timely grid upgrades. Lengthy energization queues impact project economics and are essential considerations for customers planning new loads. Customers should be informed whether their decision to take service under an FSCA might affect their position in

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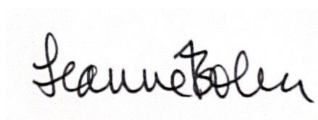
[29] PG&E June 13 Response, at 8.
[30] *Id.* at 12.

the energization queue so they can decide whether doing so is in their best interests. Likewise, non-FSCA energization applicants must be informed of the impact on their queue positions due to having an FSCA candidate on the same feeder. The Commission should require PG&E to provide a response to section 3.5, topic 2(h) to ensure all energization applicants can make informed planning decisions. While the Commission did not require SCE to respond to this topic, its energization applicants should know the impact on their queue positions due to FSCAs. Therefore, the Commission should also consider requiring SCE to respond to this topic.

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,



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

July 8, 2025

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U 39 E) for Approval of Electric Rule No. 30 for Transmission-Level Retail Electric Service.	A.24-11-007

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION PARTLY GRANTING AND PARTLY DENYING PACIFIC GAS AND ELECTRIC COMPANY'S MOTION FOR INTERIM IMPLEMENTATION OF ELECTRIC RULE NUMBER 30

Leanne Bober,
Director of Regulatory Affairs and Deputy General Counsel
Katy Morsony,
Senior Counsel and Manager of Strategic Policy Initiatives

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

Scott Blaising,
BRAUN BLAISING & WYNNE P.C.
2600 Capitol Avenue, Suite 400
Sacramento, CA 95816
Telephone: (916) 326-5812
E-mail: blaising@braunlegal.com

Counsel for CALIFORNIA COMMUNITY CHOICE ASSOCIATION

July 10, 2025

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SUMMARY OF RECOMMENDATIONS

CalCCA recommends that the Commission:

- Modify the Proposed Decision with CalCCA's three-part information-sharing proposal, including:
  - First, prior to an Interconnection Application being filed, if PG&E is incorporating customer load inquiries into its internal or external forecasts, PG&E should report to affected CCAs on a quarterly basis the approximate location, size, and anticipated timeline for integrating that new load;
  - Second, when an Interconnection Application is submitted, PG&E should provide each affected CCA a copy of the Interconnection Application within 20 calendar days of submission, with customer information including customer contact information, location, facility type, load type, capacity ramp schedule, on-site generation, and requested timing of interconnection (Key Customer Information) included. PG&E should also provide already submitted Interconnection Applications and any Key Customer Information to an affected CCA within 20 calendar days of the Commission Decision on interim implementation; and
  - Third, PG&E should provide each affected CCA with quarterly reports that provide updates on the proposed interconnection timelines related to Interconnection Applications, and any changes to Key Customer Information or timelines;
- Find that existing statutory and Commission confidentiality requirements, including non-disclosure agreements (NDAs) between PG&E and CCAs, provide adequate protection for Large Load customer information held by PG&E to be provided to CCAs. To the extent the Commission decides it must extend such confidentiality requirements to cover information sharing for Large Loads, the Commission should modify the Proposed Decision to do so;
- Modify the Proposed Decision to require PG&E to:
  - Notify potential customers through a revised Rule 30 interim implementation Tariff and any form Interconnection Agreement that if the proposed load is sited in a CCA's service area, the affected CCA is the default provider of generation service;
  - Inform the customer that, given the CCA's role and responsibility, the affected CCA is entitled to and will receive information on the customer subject to existing confidentiality protections; and
  - Revise the definition of "Retail Service" in the Rule 30 Tariff to clarify that the Rule 30 transmission interconnection does not include generation service.

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION PARTLY GRANTING AND PARTLY DENYING PACIFIC GAS AND ELECTRIC COMPANY'S MOTION FOR INTERIM IMPLEMENTATION OF ELECTRIC RULE NUMBER 30

The California Community Choice Association[1] (CalCCA) submits these comments pursuant to Rule 14.3 of the California Public Utilities Commission's (Commission's) Rules of Practice and Procedure[2] on the proposed *Decision Partly Granting and Partly Denying Pacific Gas and Electric Company's Motion for Interim Implementation of Electric Rule Number 30,*[3] dated June 20, 2025.

I. INTRODUCTION

Pacific Gas and Electric Company (PG&E), in its Rule 30 Application[4] and elsewhere, reports on the enormous and unprecedented increase in transmission interconnection requests by data centers and other large loads (Large Loads). Community choice aggregators (CCAs), as the default generation providers in their service territories, must prepare to provide generation service for much of this load. Indeed, PG&E has reported that "a significant number of the very large load applications received thus far are for projects within areas served by [CCAs]."[5] Despite PG&E's representations, and despite new customers automatically being enrolled as CCA generation customers (subject to the customer's ability

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

[2] *State of California Public Utilities Commission, Rules of Practice and Procedure, California Code of Regulations Title 20, Division 1, Chapter 1* (May 2021).

[3] Proposed *Decision Partly Granting and Partly Denying Pacific Gas and Electric Company's Motion for Interim Implementation of Electric Rule Number 30*, Application (A.) 24-11-007 (July 20, 2025) (Proposed Decision).

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

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

to opt out), CCAs have been largely left in the dark regarding timely, crucial information on these Large Load customers seeking service in CCA service territories.

As noted throughout this proceeding, CalCCA and its member CCAs support PG&E's goal of efficiently interconnecting transmission-level customers. Rule 30 will likely streamline that process, including through the Proposed Decision's allowance of interim implementation. The Commission first acknowledged the importance of information-sharing with CCAs in the Scoping Memo, which includes as Item 4.b. the following scoping question:

> What information-sharing requirements should PG&E adopt to ensure that the CCA affected by Rule 30-related load growth can meet projected demand in their service areas?[6]

In addition, the Proposed Decision acknowledges the "significance of providing timely information to the CCAs . . . to enhance planning and reliability."[7] While these acknowledgments are appreciated, they fail to go far enough to achieve what should be a non-controversial practice – ensuring CCAs along with PG&E have timely information to enable reliable, cost-effective procurement.

Large Load customers interconnecting at the transmission-level often have a choice of where to locate a new facility. If California seeks to attract and retain these customers—and benefit from the downward pressure on delivery rates their participation can provide—the state must adopt policies that enhance the optionality and support available to Large Load customers. Key among these policies is ensuring coordination between PG&E and CCAs, as the default generation service providers in their service areas. Of course, this coordination should adhere to Commission established and statutory confidentiality rules for PG&E and CCA handling of private customer information. CalCCA therefore requests that the Commission revise the Proposed Decision to adopt a simple, timely information-sharing framework among PG&E and the affected CCAs.

CalCCA therefore recommends that the Commission:

- Modify the Proposed Decision with CalCCA's three-part information-sharing proposal, including:
    - First, prior to an Interconnection Application being filed, if PG&E is incorporating customer load inquiries into its internal or external forecasts, PG&E should report to affected CCAs on a quarterly basis the approximate location, size, and anticipated timeline for integrating that new load;

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6 A.24-11-007, *Assigned Commissioner's Scoping Memo and Ruling on Pacific Gas and Electric Company's Request to Implement a New Electric Rule 30 Tariff* (Mar. 11, 2025), at 8.

7 Proposed Decision, at 34.

- Second, when an Interconnection Application is submitted, PG&E should provide each affected CCA a copy of the Interconnection Application within 20 calendar days of submission, with customer information including customer contact information, location, facility type, load type, capacity ramp schedule, on-site generation, and requested timing of interconnection (Key Customer Information) included. PG&E should also provide already submitted Interconnection Applications and any Key Customer Information to an affected CCA within 20 calendar days of the Commission Decision on interim implementation; and
- Third, PG&E should provide each affected CCA with quarterly reports that provide updates on the proposed interconnection timelines related to Interconnection Applications, and any changes to Key Customer Information;

- Find that existing statutory and Commission confidentiality requirements, including non-disclosure agreements (NDAs) between PG&E and CCAs, provide adequate protection for Large Load customer information held by PG&E to be provided to CCAs. To the extent the Commission decides it must extend such confidentiality requirements to cover information sharing for Large Loads, the Commission should modify the Proposed Decision to do so;
- Modify the Proposed Decision to require PG&E to:
    - Notify potential customers through a revised Rule 30 interim implementation Tariff and any form Interconnection Agreement that if the proposed load is sited in a CCA's service area, the affected CCA is the default provider of generation service;
    - Inform the customer that, given the CCA's role and responsibility, the affected CCA is entitled to and will receive information on the customer subject to existing confidentiality protections; and
    - Revise the definition of "Retail Service" in the Rule 30 Tariff to clarify that the Rule 30 transmission interconnection does not include generation service.

II. BACKGROUND

A. PG&E's Rule 30 Application Has Been Submitted in the Context of Unprecedented Load Growth

PG&E's Rule 30 Application has been submitted in light of "a significant increase in requests" for transmission-level service.[8] PG&E states that the historical average for transmission-level service was 2.7 projects per year between 2014 and 2022, or 24 total retail customers with four megawatts (MW) or more of demand, for a total of 196 MW.[9] Beginning in 2023, however, given the substantial growth of data centers and other Large Loads, applications for transmission level interconnections have increased over 4,000 percent, with a requested load for 40 applications of <u>8,422 MW</u> at the time

[8] Application, at 3.
[9] PG&E Supplemental Testimony, A.24-11-007 (Mar. 21, 2025) (replacing PG&E's originally filed Testimony, submitted Nov. 21, 2024) (PG&E Testimony), at 3, lines 11-15.

PG&E's testimony was submitted in March, 2025.[10] PG&E states that 75 percent of the Large Load requests are from data centers, the growth of which PG&E expects to continue.[11] PG&E represents that as of April, 2025, none of these applications have been withdrawn, and all are in the study/planning or design phases.[12] Significantly, in a May 28, 2025, presentation regarding load growth trends, PG&E states that its "data center pipeline" now stands at 14,219 MW. Around the same time, PG&E's Vice President of Energy Policy and Procurement, stated that "12.8 [GW] of applications have been submitted and about 1.4 GW of that is already through final engineering and so we do think about 90 percent of what's in final engineering will come to bear."[13] Regardless of the exact magnitude of Large Loads planning to interconnect to PG&E's transmission system, the publicly stated numbers are staggering and unprecedented, and will require significant planning to ensure reliability and affordability for all customers.

Given this unprecedented growth in transmission interconnection applications, PG&E submitted its Rule 30 Tariff Application on November 21, 2024, to create "a streamlined, transparent, and equitable approach for interconnecting" new transmission-level customers. PG&E's stated intent with its Rule 30 Application is to "eliminate the time and resources required to negotiate individual transmission-level customer agreements and then submit these agreements to the Commission through a Tier 3 Advice Letter for review and approval through an "exceptional case filing" through its existing distribution-level interconnection tariffs.[14] According to PG&E, Rule 30 will allow transmission-level customers to "efficiently and uniformly interconnect" through form rules and agreements.[15] Throughout the Rule 30 proceeding, CCAs have indicated their support for PG&E's

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[10] *Id.*, at 4, lines 1-7.

[11] *Id.*, at 5, lines 8-12 ("As technology continues to advance, we are seeing the growth of Data Centers in our service territory and expect this growth to continue with the large amounts of electrical demand needed to power such facilities.").

[12] *Pacific Gas and Electric Company's (U 39 E) Response to Administrative Law Judge's Ruling Requesting Information on the Motion for Interim Implementation of Electric Rule No. 30 [Public Version],* A.24-11-007 (Apr. 4, 2025) (PG&E Response to Interim Implementation Ruling), at 3, 8.

[13] FERC Docket AD25-7-000, Comments of Gillian Clegg, PG&E Vice President, Energy Policy and Procurement, "Day 2: Commissioner-led Technical Conference Regarding the Challenge of Resource Adequacy in RTO and ISO Regions" (June 5, 2025), at 5:33, video recording available at: https://ferc.gov/news-events/events/day-2-commissioner-led-technical-conference-regardingchallenge-resource (transcribed from video).

[14] PG&E Electric Rules 15.I.3 and 16.G (addressing exceptional case filings).

[15] Application, at 6.

Rule 30 Tariff, but highlighted the need to incorporate timely information sharing given the characteristics and potentially accelerated nature of these transmission interconnections.[16]

B. Motion for Interim Implementation and Proposed Decision

PG&E submitted a Motion for Interim Implementation of Rule 30 on January 24, 2025, requesting that the Commission authorize it to utilize Rule 30, including the proposed form agreement, on an interim basis pending the outcome of the proceeding.[17] PG&E states in its Motion that:

> New retail electric customers requesting transmission level service cannot simply wait for a year, or likely longer, for a decision on Electric Rule 30. These entities, many of whom are considering investing hundreds of millions of dollars in California's economy through the construction of new facilities such as data centers and electric vehicle (EV) charging infrastructure, are subject to commercial realities that require more immediate action and certainty.[18]

PG&E did not address the Joint CCAs' request for customer information in its Motion, other than proposing to provide "quarterly informational submissions" regarding form agreements entered into

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[16] For example, in response to PG&E's Rule 30 Application, six CCAs located in PG&E's service territory (Ava, 3CE, MCE, PCE, RCEA, SJCE, and SVCE (collectively the Joint CCAs)) on February 10, 2025, filed a Response to PG&E's Rule 30 Application, "support[ing] PG&E's goal of more efficiently extending its transmission system to serve new customers while reducing cost risk for existing customers." The Joint CCAs, however, highlighted the need for "timely dissemination of key load growth information" and that:

> PG&E should be required to share a broad range of data with CCAs in a timely and coordinated manner. For example, PG&E should share not only timely forecast information, but also expressions of interest regarding transmission-level retail interconnection service. In this way, CCAs will have the same critical information that PG&E has so that CCAs may make informed and necessary procurement adjustments to accommodate expanding load.

The Joint CCAs also stated that existing confidentiality protections, including NDAs regarding customer information, are sufficient to protect information shared by PG&E with an affected CCA.

In its Reply dated February 18, 2025, PG&E stated that:

> Communication and collaboration with the Joint CCAs, . . . will occur during the course of this proceeding and does not need to be a separate issue. As to providing confidential information, PG&E looks forward to working with Joint CCAs as to whether sharing confidential information and how to do so is appropriate in this proceeding. However, this does not need to be a separate issue.

CalCCA entered the case on behalf of the six CCAs and its other members on June 18, 2025. *See Email Ruling Granting California Community Choice Association's Motion for Party Status*, A.24-11-007 (June 18, 2025).

[17] A.24-11-007, *Pacific Gas and Electric Company's (U 39 E) Motion for Interim Implementation of Electric Rule No. 30* (Jan. 24, 2025).

[18] *Id.* at 3.

and "lessons learned to date based on the interim implementation."[19] PG&E stated that given the "commercially sensitive information . . . such as the names of entities applying for service and the size and location of the Applicant's facilities," it would include a "public version of the quarterly report to parties on the service list" and a "confidential version to the Commission and Commission Staff."[20]

The Joint CCAs responded to PG&E's Motion, again supporting PG&E's proposed Rule 30 but requesting PG&E share customer information regarding the transmission interconnections on a timely basis with CCAs. In data request responses, PG&E stated that it has not provided notice regarding new interconnection applications because Rule 30 "concern[s] the physical interconnection of a facility into PG&E's electric system . . . [and] [t]hese applications do not concern the provision or procurement of electric commodity service."[21] Similarly, in its Reply to the Joint CCA's response, PG&E stated that the issues raised by the Joint CCAs are outside the scope of the proceeding, but that "it looked forward to working with the Joint CCAs on information sharing protocols outside this proceeding" and that "interim implementation should not be denied simply because PG&E and the Joint CCAs have not yet reached an agreement on information sharing."[22]

C. As Default Generation Providers, CCAs Need Timely Notice from PG&E of Large Loads Interconnecting to the Electric System

While PG&E is the default provider of delivery (including distribution and transmission) service, CCAs are the default providers of generation service in their service territories.[23] The eleven CCAs in PG&E's service territory provide 46 percent of the electric generation service in PG&E's entire service territory, and serve on average 92 percent of customers within their own service territories.[24] The percentage of electric generation service in PG&E's service territory served by CCAs is expected to increase in the next two years and beyond.[25]

PG&E and CCAs both play key roles with respect to these new Large Load customers. Given the sophistication of Large Load customers, the customer choice framework in California provides an

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19 *Id.* at 15.

20 *Ibid.*

21 A.24-11-007, *Response of the Joint Community Choice Aggregators to Pacific Gas and Electric Company's Motion for Interim Implementation* (Feb. 10, 2025), at 13-14.

22 A.24-11-007, *Pacific Gas and Electric Company's (U 39 E) Reply to Responses Regarding Motion for Interim Implementation of Electric Rule No. 30* (Feb. 18, 2025), at 27.

23 Public Utilities Code § 366.2(c)(2).

24 *See* CalCCA website, "CCA: Power in Numbers": https://cal-cca.org/cca-impact/.

25 For example, in September 2024, Ava submitted its expansion plan for service to San Joaquin County. In March 2025, Pioneer submitted its expansion plan for service to multiple communities in northern California.

opportunity for CCAs to present their options, while the customer also has the option to choose receiving generation service from PG&E or ESP. While PG&E seeks to streamline its transmission interconnection processes through Rule 30, it has also indicated its intent to develop tailored generation service options for Large Load customers in its General Rate Case, Phase 2.[26] CCAs must likewise consider service options that reflect both their local priorities and governance.

The lack of information regarding planned Large Loads creates multiple disadvantages for CCAs and CCA customers, such as: (1) lack of parity between CCAs and PG&E; (2) inadequate information to plan for reliability; (3) lack of notice to customers of their generation service options; and (4) inability to capitalize on affordability benefits of cost-effective procurement. As a result, the Commission should require PG&E to provide CCAs with timely information, which can be provided under existing confidentiality rules, regarding these new Large Load customers. To the extent the Commission decides it must amend the confidentiality rules regarding information sharing for Large Loads, it can do so through the Proposed Decision.

1. Large Load Customer Information Provided by PG&E to Default Provider CCAs is Untimely and Inadequate to Realize the Benefits of Cost-effective Generation Procurement

Under current practices, Large Load customer information provided by PG&E to default provider CCAs is untimely and inadequate to realize the benefits of cost-effective procurement. As the delivery service provider for customers in its territory, PG&E is often the first stop for a new Large Load considering locating a facility in California. CCAs often receive limited, if any, advance notice of new customer load. For Rule 15 and 16 distribution level interconnections, CCAs often do not receive notice of the new load until energization pursuant to Rule 23.K.2., which directs PG&E to "promptly notify" the CCA of the new customer "at the time their electric service becomes active."[27] Because transmission interconnection agreements are submitted under the "exceptional case filing" requirement, CCAs may get notice upon such a public filing which occurs before energization but does not occur until after a Preliminary Engineering Study has been completed and an interconnection agreement has been negotiated. Such a filing usually does not occur until *years after* an interconnection application is filed. For example, with a recent PG&E "exceptional case filing" for a transmission-level interconnection, SJCE as the default provider of generation service did not receive

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[26] *See* A.24-09-014.

[27] PG&E Electric Rule 23.K., Sheet 32.

notice of a new 90 MW data center in SJCE's territory until nearly *five years* after PG&E began its active engagement with the customer.[28]

Cost-effective procurement requires the CCA to consider the needs of each individual customer as well as the broader compliance requirements for the CCA, including Resource Adequacy (RA), Integrated Resource Planning (IRP), and Renewables Portfolio Standard (RPS) requirements. The further in advance the CCA can assess the needs of a particular customer and the timing of its energization, the better able the CCA is to engage in a thoughtful, cost-effective, and dynamic procurement strategy. This strategy includes purchasing energy in long, medium, and short-term markets to ensure that the CCA can cost-effectively meet the needs of its customers without unnecessary reliance on any one market.

A dynamic procurement strategy is reliant on good data. Without timely information about potential new load, and in particular Large Loads, and the timing of interconnection, a CCA could under or over procure, increasing risk to its supply portfolio and customers. Indeed, PG&E's Vice President of Energy Policy and Procurement recently noted the need for certainty and timeliness of information regarding new loads, and especially Large Loads, when discussing PG&E's current RA challenges at a Federal Energy Regulatory Commission (FERC) conference:

> Another challenge is significant uncertainty (e.g., timing and volume) associated with incremental large loads, such as data centers. In some cases, these are material incremental loads (1 GW or greater) that significantly change grid needs once connected. The timing for satisfying the reliability need must align with the timing to procure sufficient resources to serve the load to avoid reliability and affordability challenges associated with either delayed or premature procurement and system upgrades.[29]

CCA procurement strategies begin with the load forecast in the California Energy Commission's Integrated Energy Policy Report (IEPR) process as well as CCA internal load forecasting, which become more refined over time as better information about individual customers becomes available. However, the IEPR forecast, which materially impacts CCA compliance

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[28] *See* PG&E Advice Letter 7569-E (Apr. 18, 2025) (proposing interconnection at transmission-level of a 90 MW data center for STACK, a retail customer, in SJCE's service territory in San Jose, California); *see also Joint Community Choice Aggregators' Response to PG&E's Advice Letter 7569-E* (May 8, 2025) (objecting to the failure of PG&E to provide notice to SJCE).

[29] FERC Docket AD25-7-000, *Pacific Gas and Electric Company's Advance Materials for Technical Conference on June 5th, 2025 – Remarks of Gillian Clegg, PG&E Vice President, Energy Policy and Procurement* (May 16, 2025), at 3-4.

requirements for RA, RPS, and IRP, provides the forecast in the aggregate with no detail on specifics regarding the new customer or their individual needs. For instance, a new customer may be intending to purchase its own specific product (*e.g.,* 24/7, carbon free), which would impact the procurement choices made on behalf of the customer. Details on ramp schedule, load type, and interconnection schedule will also impact the type and timing of the procurement and should be made known to CCAs at the time PG&E has the information.

In sum, there should be no material difference in the amount of time PG&E, as the delivery service provider, has customer-specific information and the amount of time CCAs have the same customer-specific information. The more notice available, the more effective the CCA can be in its procurement. This will result in cost savings for customers.[30] Therefore, reasonable requirements for timely information sharing are needed as they will empower the affected CCA to cost-effectively procure generation for new Large Loads.

2. Existing Protections for Customer Confidentiality Already Apply to Large Load Customer Information

Among PG&E's concerns regarding providing CCAs with customer information upon PG&E learning of the customer is customer confidentiality. However, as the default generation service providers, CCAs are entitled to customer information pursuant to statute and rules established by the Commission. For example, Public Utilities Code section 366.2(c)(9) requires PG&E to:

> Cooperate fully with an [CCA], . . . include[ing] providing . . . appropriate billing and electrical load data, including but not limited to, electrical consumption data . . . and other data detailing electricity needs and patterns of usage, as determined by the commission, and in accordance with procedures established by the commission.

The Commission has also asserted its jurisdiction over allowing CCAs access to customer information. In D.04-12-046, the Commission directed the IOUs to provide relevant customer information to CCAs "investigating, pursuing or implementing a CCA program."[31] The Commission acknowledged "that CCAs may need specific usage information in order to market their services and tailor those services to customer needs" even while the CCA is still pre-operational.[32] The Commission agreed with the

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30 *See id.,* at 11-14.

31 D.04-12-046, *Order Resolving Phase 1 Issues on Pricing and Costs Attributable to Community Choice Aggregators and Related Matters*, R.03-10-003 (Dec. 21, 2004), at 50.

32 *Id*. at 51-52.

assumption in the CCA enabling legislation (Assembly Bill 117[33]) that "CCAs can be entrusted with confidential customer information."[34]

In D.12-08-045, the Commission made various additional determinations with respect to CCAs' access to and responsibility for customer information.[35] The Commission was clear that CCAs' access to and use of customer information are on par with the IOUs' access to and use of such information. The Commission cited its "full authority to require CCAs which receive . . . data from [the IOUs] to comply with privacy rules," and stated that its privacy policy broadly affords "CCAs with all rights to data that it requests." The only condition for access to customer information is that the CCA enter into the NDA with the IOU, which all CCAs have.[36] Therefore, the existing confidentiality protections are sufficient to cover the Large Loads information.

To the extent the Commission decides it must extend such confidentiality requirements to cover information sharing for Large Loads, the Commission should modify the Proposed Decision to do so. Specifically, the Commission could incorporate the following requirement into its findings, as set forth in Appendix A attached hereto:

> <u>All customer information provided by PG&E to an affected CCA pursuant to this Decision is subject to the existing confidentiality rules for CCAs set forth in D.12-08-045, including the non-disclosure agreements between PG&E and each CCA.</u>

D. PG&E Has Stated It Does Not Object to the Commission Providing Clear Guidance on Information Sharing

PG&E has stated it does not object to the Commission providing clear guidance on information sharing during the Rule 30 interconnection process. PG&E noted in its Supplemental Testimony that it "would support reporting requirements to inform electric system planning process, subject to

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33 Assembly Bill 117 (AB 117) (Migden, Chapter 848, Statutes of 2002).

34 D.04-12-046, at 51 ("We believe AB 117 assumes, as we do, that CCAs can be entrusted with confidential customer information. Unlike energy service providers offering direct access, CCAs are government agencies. As long as some basic protections are in place, the risks of providing confidential information to these entities is outweighed by the dictates of the statute and the potential benefits CCA customers would realize only if CCAs have the information they need to make fully informed decisions regarding energy procurement, service requirements and resource planning decisions.")

35 D.12-08-045, *Decision Extending Privacy Protections to Customers of Gas Corporations and Community Choice Aggregators, and to Residential and Small Commercial Customers of Electric Service Providers,* R.08-12-009 (Aug. 31, 2012), at 4, 23-26.

36 All CCAs are currently subject to a "Community Choice Aggregator Non-Disclosure Agreement," PG&E Form No. 79-1031.

appropriate confidentiality protections for customer-specific information."[37] PG&E also stated in discovery responses that:

> PG&E believes that, in general, Commission direction regarding the types of potential transmission level customer information to be provided to the CCAs would be helpful so that it is clear to transmission level customers and CCAs what information will be provided by PG&E and when. Electric Rule 27 is a good example of the type of Commission direction that is helpful regarding privacy and security requirements for customer data. ***PG&E does not object to the Commission issuing clear guidance in the proceeding*** regarding: (1) what potential transmission level customer information can be provided to CCAs and when; (2) the need for an updated Non-Disclosure Agreement to protect this information; and (3) the need for CCAs to conduct privacy and cyber-security reviews before receiving this information. PG&E also suggests the CPUC include language similar to Electric Rule 27 limiting PG&E's liability once the customer information is shared with CCA. However, PG&E recognizes that it and the CCAs may have different positions on these issues.[38]

In addition, as noted above, PG&E stated it would welcome "clear guidance" regarding information-sharing and confidentiality from the Commission in reply to the Joint CCAs' responses regarding the STACK Advice Letter.

While CalCCA does not agree with PG&E that additional confidentiality protections beyond the already existing Commission requirements and NDAs are necessary, CalCCA acknowledges and appreciates PG&E's request for the Commission to provide guidance on Rule 30 information-sharing. While the Proposed Decision addresses the CCAs needs and "recognizes [their] significance," the Proposed Decision errs by failing to modify the timing of CCAs receiving customer information, as set forth below.

III. THE PROPOSED DECISION ERRS IN FAILING TO DIRECT PG&E TO PROVIDE TIMELY LARGE LOAD INFORMATION TO CCAS

The Proposed Decision errs in failing to direct PG&E to provide timely large load information to CCAs. The Proposed Decision will allow Rule 30 interim implementation to "significantly reduce the time for each application from 18-22 months to 2-5 months, alleviating substantial administrative and timing challenges" for Large Loads.[39] The Proposed Decision also "recognizes the significance of

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[37] PG&E Testimony, at 55, lines 9-11.

[38] PG&E Answer to Data Request Joint CCAs_004-Q003 (June 9, 2025) (attached hereto in Appendix B) (emphasis added).

[39] Proposed Decision, at 25.

providing timely information to the CCAs and other load serving entities to enhance planning and reliability."[40] In light of this, the Proposed Decision requires PG&E to "incorporate the information in Attachment 1 of the decision into the Tier 2 Advice Letter process" proposed by PG&E.[41] The Proposed Decision also adopts PG&E's proposal to submit quarterly information submissions describing any new form agreements by applicants and any "lessons learned to date based on the interim implementation."[42]

While requiring additional information in the Advice Letters and quarterly reports is a step in the right direction, these actions by themselves are insufficient. Two fundamental issues result in the Proposed Decision failing to materially change the insufficient information-sharing process currently in existence. First, the timing of CCAs obtaining the customer information under the Proposed Decision is no different than the status quo – that is, the affected CCA will still only receive notice of the new Large Load upon PG&E's submission of the executed Interconnection Agreement with the Commission. Even then, it is unclear if PG&E would be required to provide supposedly confidential information to the affected CCA. As noted above, a recent Tier 3 Advice Letter of a transmission-interconnection agreement occurred over four years after PG&E became aware of the customer with no notice provided of the new load to the CCA. Those four years are crucial for CCA forecasting and procurement planning, especially if the interim implementation of Rule 30 accelerates the timeframe for Commission approval of the agreement as represented by PG&E.

Second, PG&E's proposal adopted by the Proposed Decision includes PG&E's anticipatory declaration that "PG&E may need to designate certain portions of the [Tier 2 Advice Letter] as confidential if it contains commercially sensitive third-party information."[43] With respect to the quarterly reports, PG&E states that "[t]here will likely be commercially sensitive information regarding the implementation of Electric Rule 30 such as the names of entities applying for service and the size and location of the Applicant's facilities."[44] Therefore, PG&E states that it "would need to provide a public version of the quarterly report to parties on the service list and could provide a confidential version to the Commission and Commission Staff."[45] As the Proposed Decision allows

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40 *Id.* at 34.
41 *Id.* at 33-34.
42 PG&E Interim Implementation Motion, at 15.
43 *Id.* at 14.
44 *Ibid.*
45 *Ibid.*

PG&E's motion regarding the Tier 2 Advice Letter and quarterly reports, but fails to address PG&E's confidentiality framework, it appears PG&E may submit the new information under seal which would prevent CCAs from obtaining the information.

The new information-sharing requirements established in the Proposed Decision fail to materially or practically change the status quo, and therefore the Proposed Decision should be modified. By failing to require PG&E to share customer-specific load forecasts and Interconnection Applications, the Proposed Decision undermines customer choice, affordability, and reliability frustrating CCAs' ability to timely and cost-effectively procure for new customers. Only when appropriate information-sharing requirements are ordered by the Commission will the Rule 30 Large Load Tariff be just and reasonable, whether adopted on an interim basis or permanently. Accordingly, CalCCA recommends below a simple three-part information sharing proposal which should be adopted in the Proposed Decision. In addition, the Commission should acknowledge that existing confidentiality protections between PG&E and the CCAs adequately protect sensitive Large Load customer information. Alternatively, the Commission can extend such confidentiality protections to incorporate the information.

IV. THE PROPOSED DECISION SHOULD BE REVISED TO REQUIRE PG&E TO PROVIDE TIMELY LARGE LOAD INFORMATION TO CCAS

The Proposed Decision should be revised to incorporate CalCCA's proposed information-sharing framework between PG&E and any affected CCA in connection with interim implementation of the Rule 30 Tariff. CalCCA recommends that the Commission adopt the following framework between PG&E and any affected CCA:

- **Pre-Interconnection Application:** For loads for which no Application for interconnection service under Rule 30 (Interconnection Application) has been filed, but a load inquiry has been made to PG&E and the utility is incorporating the forecast into internal or external forecasts, PG&E should report to CCAs on a quarterly basis the approximate location, size, and anticipated timeline for integrating the new load. Information should be provided on a per-project basis with a unique identifier that protects the customer's identity if the customer does not wish to have their information shared with the CCA.
- **Post-Interconnection Application:** When an Interconnection Application has been submitted, PG&E should provide each affected CCA a copy of the Interconnection Application within 20 calendar days of submission to PG&E, along with customer

information, including customer contact information, location, facility type, capacity ramp schedule, on-site generation, and timing of interconnection (Key Customer Information). PG&E should also provide all already submitted Applications for Interconnection, and any additional Key Customer Information, to an affected CCA within 20 calendar days of the Commission Decision incorporating this framework.

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

In addition, as stated above, the Commission should find that existing confidentiality protections and NDAs between PG&E and affected CCAs are sufficient to ensure protection of confidential customer information. Alternatively, the Commission can extend such confidentiality protections to incorporate the information.

To ensure customer awareness of the CCA as default generation provider and the information-sharing framework, the Commission should also:

- **Customer Notification of CCA:**
  - Require notification to customers through the approved Rule 30 interim implementation Tariff and any form Interconnection Agreement that if the proposed load is sited in a CCA's service area, the affected CCA is the default provider of generation service; and
  - Require PG&E to inform the customer that, given the CCA's role and responsibility, the affected CCA is entitled to and will receive information on the customer.
- **Rule 30 Tariff Language:** Require PG&E to add the information framework to its Proposed Rule 30 Tariff, as set forth in Appendix A, attached hereto.
- **Rule 30 Interconnection Agreement Language:** Require PG&E to include in its proposed Rule 30 Interconnection Application language consistent with the information-sharing requirements. In addition, the Interconnection Application should provide a tool to assist the applicant to determine if the proposed facility will be in a CCA's service area. For any proposed facility in a CCA's service area, PG&E should provide information on how to contact the CCA and, as noted above, clear disclosures that the information will be provided to the affected CCA as the facility's default provider of generation service.

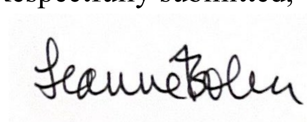
V. THE PROPOSED DECISION SHOULD REQUIRE THE REVISION OF RULE 30 TO CLARIFY THAT "RETAIL SERVICE" DOES NOT INCLUDE GENERATION SERVICE

Ambiguity exists in the Rule 30 Tariff language regarding the definition of "Retail Service." Given concerns regarding customer lack of awareness of a CCA as default generation provider in the applicable service territory, the proposed Rule 30 Tariff (including the Tariff implemented on an interim basis) should be updated as proposed by PG&E in discovery,[46] and set forth in Appendix A, attached hereto, to ensure customers understand that the Rule 30 "Retail Service" does not include or relate to providing generation service and/or an electric commodity, but rather is limited to the transmission interconnection only.

VI. CONCLUSION

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

Respectfully submitted,



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

July 10, 2025

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46 *See* PG&E Answer to Data Request Joint CCAs_001-Q006, Question 06 (Jan. 29, 2025) (attached hereto in Appendix B). (PG&E answering that it "is willing to work with the Joint CCAs to clarify that the term 6 "Retail Service" does not include or relate to generation service" and providing a proposed addition to the definition, which is acceptable to CalCCA).

APPENDIX A
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION PARTLY GRANTING AND PARTLY DENYING PACIFIC GAS AND ELECTRIC COMPANY'S MOTION FOR INTERIM IMPLEMENTATION OF ELECTRIC RULE NUMBER 30

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

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

FINDINGS OF FACT

29. CCAs and other load serving entities can utilize timely information for resource planning and reliability in response to the system load. **<u>CCAs as the default providers of electric generation service in their service territories within PG&E's service territory should have access to new system load information at the same time as PG&E to allow CCAs to cost-effectively procure to prepare for the new load.</u>**

32. PG&E's April 4, 2025 Motion requests confidentiality of customer-specific data, which may include demand, loads, names, addresses, and billing, data. **<u>CCAs as the default providers of electric generation service in their service territories within PG&E's service territory should have access to such confidential information under existing Non-Disclosure Agreements with PG&E.</u>**

CONCLUSIONS OF LAW

12. It is reasonable to require PG&E to submit additional information required for grid planning needs as described in Attachment 1 of this decision as part of the Tier 2 Advice Letter. **<u>It is also reasonable to require PG&E to provide CCAs, as the default generation provider in their service territories within PG&E's service territory, with customer information prior to an interconnection application for loads PG&E is incorporating its internal or external forecasts. It is also reasonable to require PG&E to provide such CCAs a customer Interconnection Application, with customer information including customer contact information, location, facility type, capacity ramp schedule, on-site generation, and requested timing of interconnection, within 20 calendar days of submission. It is also reasonable to require PG&E to provide such CCAs all already submitted Applications for Interconnection, including customer contact information, location, facility type, capacity ramp schedule, on-site generation, and requested timing of interconnection, within 20 calendar days of the final Decision. It is also reasonable to require PG&E to provide each affected CCA with quarterly reports that provide updates on the proposed interconnection timelines related to Interconnection Applications, and any changes to customer information within already submitted Interconnection Applications. All customer information provided by PG&E to an affected CCA pursuant to this Decision is subject to the existing confidentiality rules for CCAs set forth in D.12-08-045, including the non-disclosure agreements between PG&E and each CCA.</u>**

ORDERING PARAGRAPHS

New Ordering Paragraph:

Pacific Gas and Electric Company shall adopt the following load information-sharing requirements with any community choice aggregator in which a customer seeks to interconnect within that CCAs service territory:

a. **For loads for which no application for interconnection service under Rule 30 (Interconnection Application) has been submitted to PG&E, but a load inquiry has been made to PG&E and the utility is incorporating the forecast into internal or external forecasts, PG&E should report to the affected CCA on a quarterly basis the approximate location, size, and anticipated timeline for integrating the new load.**

b. **When an Interconnection Application has been submitted, PG&E should provide each affected CCA a copy of the Interconnection Application within 20 calendar days of submission to PG&E, with all information relevant to potential CCA service including customer contact information, location, facility type, capacity ramp schedule, on-site generation, and requested and current expected timing for the interconnection. PG&E should also provide all already submitted Applications for Interconnection, and all information relevant to potential CCA service including customer contact information, location, facility type, capacity ramp schedule, on-site generation, and requested and current expected timing for the interconnection, to an affected CCA within 20 calendar days of a Commission directive to do so.**

c. **PG&E should provide each affected CCA with quarterly reports that provide updates on the proposed interconnection timelines related to customer Interconnection Applications, and any changes to customer information.**

d. **All customer information provided by PG&E to an affected CCA pursuant to this Decision is subject to the existing confidentiality rules for CCAs set forth in D.12-08-045, including the non-disclosure agreements between PG&E and each CCA.**

NEW PG&E RULE 30 TARIFF SECTIONS:

Section 1. General

8. For any Facility at a location within the service area of a Community Choice Aggregator (CCA), the CCA is the default provider of generation service. The affected CCA will automatically serve any new Applicant in its service area subject to the choice of the Applicant to opt out of CCA service to receive generation service from PG&E. Upon receipt of an Application for a Facility in a CCA's service area, PG&E will provide the affected CCA a copy of the Application within 20 calendar days of receipt, to ensure the CCA receives key information about the service request to inform the CCA of the

new customer, including the customer contact information, location, facility type, capacity ramp schedule, on-site generation, and requested timing for the interconnection. PG&E will also provide to the affected CCA within 20 calendar days any subsequent changes to the Application and periodic updates to the interconnection timeline. Information provided by PG&E to the CCA is subject to confidentiality protections established by the Commission.

Definitions

RETAIL SERVICE: Electric service to PG&E's end-use or retail customers 30 which is of a permanent and established character and may be continuous, intermittent, or seasonal in nature. **For purposes of this Rule, Retail Service does not include or relate to providing generation service and/or the electric commodity.**

APPENDIX B
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION PARTLY GRANTING AND PARTLY DENYING PACIFIC GAS AND ELECTRIC COMPANY'S MOTION FOR INTERIM IMPLEMENTATION OF ELECTRIC RULE NUMBER 30

PG&E Answer to Data Request Joint CCAs_001-Q006 (Jan. 29, 2025)
and
PG&E Answer to Data Request Joint CCAs_004-Q003 (June 9, 2025)

PACIFIC GAS AND ELECTRIC COMPANY
Electric Rule 30 – Transmission-Level Interconnections
Application 24-11-007
Data Response

PG&E Data Request No.:	JointCCAs_001-Q006
PG&E File Name:	ElectricRule30-Transmission-LevelInterconnections_DR_JointCCAs_001-Q006
Request Date:	January 23, 2025
Requester DR No.:	001
Requesting Party:	JointCCAs
Requester:	Scott Blaising
Date Sent:	January 29, 2025
PG&E Witness(es):	Ben Moffat – Engineering, Planning and Strategy

QUESTION 006

In Attachment A to Chapter 2 of the PG&E Testimony, PG&E sets forth a proposed rule that, among other things, contains the following definition for "Retail Service": "Electric service to PG&E's end-use or retail customers which is of a permanent and established character and may be continuous, intermittent, or seasonal in nature." (PG&E Testimony at 2-AtchA-17.)

a. As related to issues in this proceeding, is PG&E amenable to changing the term "Retail Service" to "Retail Delivery Service" or another term that does not imply that the service described in Proposed Rule 30 relates to or includes generation service?

    i. If not, please explain why PG&E is not amenable.

    ii. If so, please provide a description of the revised term that PG&E agrees to use.

ANSWER 006

PG&E is willing to work with the Joint CCAs to clarify that the term "Retail Service" does not include or relate to generation service. As an initial proposal, PG&E suggests adding the following sentence to the defined term "Retail Service":

> For purposes of this Rule, Retail Service does not include or relate to providing generation service and/or the electric commodity.

TPACIFIC GAS AND ELECTRIC COMPANY
Electric Rule 30 – Transmission-Level Interconnections
Application 24-11-007
Data Response

PG&E Data Request No.:	JointCCAs_004-Q003
PG&E File Name:	ElectricRule30-Transmission-LevelInterconnections_DR_JointCCAs_004-Q003
Request Date:	May 26, 2025
Requester DR No.:	004
Requesting Party:	Joint CCAs
Requester:	Scott Blaising
Date Sent:	June 9, 2025
PG&E Witness(es):	David Gutierrez– Customer and Enterprise Solutions

QUESTION 003

Is PG&E aware of any current restriction or limitation on its ability to share Key Load Information[1] with CCAs in advance of energization of the New Transmission Customer. If so:

a. Please describe the restriction or limitation;

b. Please indicate whether the restriction or limitation may be eliminated if PG&E were to redact or otherwise exclude certain Key Load Information, and if so please indicate which element(s) of the Key Load Information would need to be redacted or otherwise excluded and why.

c. Please indicate whether PG&E believes the restriction or limitation could be eliminated if PG&E were to have the restriction or limitation addressed in a ruling or decision from the CPUC in this proceeding, and if so:

   i. Please describe what would need to be addressed by the CPUC in the ruling or decision; and

   ii Please indicate whether PG&E objects to the Joint CCAs requesting the issuance of a ruling or decision from the CPUC in this proceeding.

ANSWER 003

a. PG&E objects to this request as burdensome to the extent that it seeks a comprehensive list of all rules, regulations, and statutes that address the confidentiality of potential transmission level customer information. PG&E further objects to the extent this request seeks legal conclusions or attorney work product. Subject to and without waiving this objection, in general and without representing

1 Key Load Information is defined as for each transmission-level interconnection request, if and when available, (1) the facility type (e.g., data center, commercial, retail, manufacturing, agricultural, other); (2) the facility's electric capacity (MW) ramp schedule; (3) the facility's proposed address or location; and (4) the requested timing for energization.

that this is a comprehensive list, PG&E is aware of the following statutes, regulations and rules that are related to or concern the privacy of customer information: California Public Utilities Code Section 8380,CPUC Decision (D.) 11-07-056, and PG&E Electric Rule 27 all adopt rules regarding the disclosure of customer energy usage data. CPUC D.14-05-016 provides aggregation guidelines for the sharing of customer load information without customer consent.

b. PG&E objects to this request as speculative. PG&E would need to evaluate the specific information at issue, review any applicable Non-Disclosure Agreements with the potential customer, and determine what, if any, information could be redacted. Providing a generic response would be speculative.

c. PG&E believes that, in general, Commission direction regarding the types of potential transmission level customer information to be provided to the CCAs would be helpful so that it is clear to transmission level customers and CCAs what information will be provided by PG&E and when. Electric Rule 27 is a good example of the type of Commission direction that is helpful regarding privacy and security requirements for customer data. PG&E does not object to the Commission issuing clear guidance in this proceeding regarding: (1) what potential transmission level customer information can be provided to CCAs and when; (2) the need for an updated Non-Disclosure Agreement to protect this information; and (3) the need for CCAs to conduct privacy and cyber-security reviews before receiving this information. PG&E also suggests the CPUC include language similar to Electric Rule 27 limiting PG&E's liability once the customer information is shared with CCA. However, PG&E recognizes that it and the CCAs may have different positions on these issues.

Comments on discussion paper

Initiative: Demand and distributed energy market integration

Comment period

Jun 17, 2025, 12:00 pm - Jul 11, 2025, 05:00 pm

Submitting organizations

California Community Choice Association

Marin Clean Energy

California Community Choice Association

Submitted on 07/11/2025, 01:26 pm

Contact

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

1. Please provide your organization’s feedback regarding the updated DDEMI Discussion paper (which was published on June 13, 2025).

The California Community Choice Association (CalCCA) appreciates the opportunity to comment on the June 13, 2025, updated Demand and Distributed Energy Market Integration (DDEMI) Discussion Paper. CalCCA reiterates its May 1, 2025, comments on the Performance Evaluation Methodology (PEM) problem statements presented at the April 7, 2025, DDEMI Working Group (DDEMI WG) meeting, and provides a response to problem statement 3, regarding device-level measurement. In its May 1 comments, CalCCA took no position on the exploration of device-level ***measurement*** (problem statement 3) or device-level ***registration*** (problem statement 5) problem statements. CalCCA now expresses support for the DDEMI WG exploring device-level ***measurement*** via the stakeholder initiative process, as discussed in more detail below, and continues to take no position on device-level ***registration***.

CalCCA restates its May 1, 2025, recommendations that the California Independent System Operator (CAISO):

- Move the operational details of PEMs from the tariff to the Business Practice Manual (BPM) to allow flexibility for modifying PEMs to be more effective and adding PEMs to support new technologies or processes for monitoring and evaluating performance;
- Include general descriptions of PEM categories in the tariff to ensure compliance with Federal Energy Regulatory Commission (FERC) rules; and
- Work with the California Public Utilities Commission (CPUC) and stakeholders to explore opportunities to allow full export from behind-the-meter (BTM) energy storage and electric vehicles (EVs).

Additionally, the CAISO should address problem statement 3 by exploring the use of device-level

measurement in developing baselines for PEM options. The Discussion Paper defines problem statement 3 as, “BTM device-level measurement is not recognized for use in developing baselines for PEM options. Performance evaluations depend on energy measurement (load and generation) and don’t recognize non-energy metered technologies' contributions to load reduction calculation equivalents.”

Because performance at the individual BTM device level is not recognized in developing PEM baselines, the baselines could potentially undervalue their contribution to load reduction calculation equivalents. Without visibility into individual BTM devices, the CAISO cannot accurately determine their performance or forecast short-term loads. In particular, BTM energy storage charging and discharging in response to dispatch instructions could be “hidden” by other loads behind the customer meter and may be more accurately measured by device-level measurement. The DDEMI WG should therefore continue exploring device-level measurement via the stakeholder initiative process to better understand the challenges and opportunities of individual BTM device measurement.

Marin Clean Energy

Submitted on 07/14/2025, 02:20 pm

Contact

MCE Regulatory (regulatory@mcecleanenergy.org)

1. Please provide your organization’s feedback regarding the updated DDEMI Discussion paper (which was published on June 13, 2025).

Marin Clean Energy (MCE) appreciates the opportunity to comment on the updated DDEMI Discussion Paper and DDEMI Working Group (WG) schedule. As it relates to the updated Discussion Paper and proposed WG schedule:

> **MCE supports the CAISO’s proposed updates to the Performance Evaluation Methodologies (PEMs). The updated problem statements appropriately balance the DDEMI WG principles of efficiency, competition, feasibility, simplicity, reliability/compliance, and practicable facilitation of states’ public policy. MCE supports the WG moving forward with these updated problem statements in a subsequent phase.**
>
> **MCE continues to encourage the CAISO to allow for additional stakeholder presentations beyond the problem statement formation phase. Specifically, MCE recommends that the WG allows for and schedules time for stakeholder presentations in the next phases of the WG (i.e. forming solutions/actions). MCE recommends that the WG consider soliciting proposals for and authorizing Pilot programs to test alternative baseline approaches to the control group methodology. Such Pilots could be implemented in the near term by continuing to settle on existing approved PEMs, while simultaneously evaluating performance using alternative baseline techniques. As stated in its DDEMI comments submitted on May 27th, 2025, MCE is currently developing an alternative baseline method designed to enable daily participation and enhance performance value by rewarding more frequent load-shifting and encourages the CAISO to consider exploring and authorizing such Pilot programs to better inform policy changes.**

MCE encourages the CAISO to include more specificity and detail in the listed topics outlined in the WG schedule, with as much advanced notice as possible, so that stakeholders can be best prepared to discuss ideas and positions during WG meetings.

Attachments

7.11.25 MCE Comments on Updated Discussion Paper (1).docx

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U 39 E) for Approval of Electric Rule No. 30 for Transmission-Level Retail Electric Service.	A.24-11-007

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON THE PROPOSED DECISION PARTLY GRANTING AND PARTLY DENYING PACIFIC GAS AND ELECTRIC COMPANY'S MOTION FOR INTERIM IMPLEMENTATION OF ELECTRIC RULE NUMBER 30

Leanne Bober,
Director of Regulatory Affairs and Deputy General Counsel
Katy Morsony,
Senior Counsel and Manager of Strategic Policy Initiatives

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

July 15, 2025

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SUMMARY OF RECOMMENDATIONS

CalCCA[1] supports adoption of the Commission's Proposed Decision on PG&E's Motion for Interim Implementation to the extent PG&E's Reply to the Proposed Decision supports, and the Proposed Decision requires, PG&E to provide the following to the CCA in whose territory the customer seeks to interconnect:

- The customer's Application for Transmission Interconnection within 20 business days of the customer's submission to PG&E; and
- Quarterly reports providing updates on the transmission interconnection timeline, and any changes to key customer information.

[1] Acronyms used in this Summary of Recommendations are defined in the body of this document, *California Community Choice Association's Reply Comments on The Proposed Decision Partly Granting and Partly Denying Pacific Gas and Electric Company's Motion for Interim Implementation of Electric Rule Number 30*, A.24-11-007 (July 15, 2025).

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U 39 E) for Approval of Electric Rule No. 30 for Transmission-Level Retail Electric Service.	A.24-11-007

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON THE PROPOSED DECISION PARTLY GRANTING AND PARTLY DENYING PACIFIC GAS AND ELECTRIC COMPANY'S MOTION FOR INTERIM IMPLEMENTATION OF ELECTRIC RULE NUMBER 30

The California Community Choice Association (CalCCA) submits these reply comments pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure[2] on the proposed *Decision Partly Granting and Partly Denying Pacific Gas and Electric Company's Motion for Interim Implementation of Electric Rule Number 30,*[3] dated June 20, 2025.

I. CALCCA SUPPORTS INTERIM IMPLEMENTATION TO THE EXTENT PG&E SUPPORTS SHARING OF CUSTOMER APPLICATION AND POST-APPLICATION INFORMATION WITH CCAS

CalCCA supports the Proposed Decision's partial grant of Pacific Gas and Electric Company's (PG&E) Motion for Interim Implementation to the extent it also directs PG&E to provide, during the period of interim implementation, information to a community choice aggregator (CCA) regarding customer applications for interconnection at the transmission level within the CCA's service territory. PG&E and CalCCA had discussions on July 14, 2025,

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[2] *State of California Public Utilities Commission, Rules of Practice and Procedure, California Code of Regulations Title 20, Division 1, Chapter 1* (May 2021).

[3] Proposed *Decision Partly Granting and Partly Denying Pacific Gas and Electric Company's Motion for Interim Implementation of Electric Rule Number 30*, Application (A.) 24-11-007 (June 20, 2025) (Proposed Decision).

regarding CalCCA's requests in its Opening Comments[4] for PG&E to provide customer information. PG&E represented that it will be filing Reply Comments requesting that the Commission grant CalCCA's requests for PG&E to provide: (1) a customer's Application for Transmission Interconnection to the affected CCA within 20 business days of the customer's submission to PG&E; and (2) quarterly reports to the affected CCA providing updates on the transmission interconnection timeline, and any changes to key customer information.[5] To the extent PG&E's Reply Comments are consistent with these requests, and the Proposed Decision is revised to incorporate these requests (as more fully described in CalCCA's Opening Comments), CalCCA supports adoption of the Commission's Proposed Decision partially granting PG&E's Motion for Interim Implementation.

II. CONCLUSION

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

Respectfully submitted,

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

July 15, 2025

[4] *California Community Choice Association's Comments on the Proposed Decision Partly Granting and Partly Denying Pacific Gas and Electric Company's Motion for Interim Implementation of Electric Rule Number 30,* A.24-11-007 (July 10, 2025), at 13-14.

[5] PG&E represented that it would not support CalCCA's request for customer information prior to the submission of an Application for Transmission Interconnection.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Electric Integrated Resource Planning and Related Procurement Processes.	R.20-05-003

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENTS ON RELIABLE AND CLEAN POWER PROCUREMENT PROGRAM STAFF PROPOSAL

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

July 15, 2025

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SUMMARY OF RECOMMENDATIONS

- Provide LSEs[1] and developers certainty that their investments will not be undermined by regulatory shifts, given mid to long-term procurement is complex, time consuming, and capital intensive. The Commission should develop RCPPP through a robust stakeholder process that builds an adequate record and establishes a durable and stable procurement framework. The Commission should also carefully consider the practical realities of the current procurement environment (*e.g.,* continued supply chain issues, interconnection delays, and actions at the federal level impacting renewable development) when developing RCPPP and assessing the need for interim procurement requirements prior to RCPPP implementation.
- Develop the reliability and GHG-reduction frameworks on two tracks to thoroughly vet each framework. The first track should develop the reliability framework, targeting implementation in 2029 such that implementation of the RCPPP follows the conclusion of the last MTR order. The second track should develop the CES proposal, which needs additional work to develop the details, targeting implementation for a 2031-2033 compliance period, so that it takes effect following the 2028-2030 RPS compliance period.
- Commit in the near term to developing an RCPPP reliability framework based upon the Staff Proposal's Option I with the following modifications: (1) align RCPPP with the RA program using the SOD methodology; (2) establish the five-year forward showing requirements in alignment with the month-ahead and year-ahead RA processes, with a focus on critical months and hours and reduced percentage requirements in the out years to mitigate against potentially costly over-build resulting from load forecast changes; (3) remove the buffer and CCR in favor of LSE-level risk management and the RA PRM; (4) adopt a penalty waiver process as part of the reliability framework, building upon the "good faith efforts" standard adopted in the MTR Order; and (5) ensure the program is sufficiently transactable so that reliability requirements can be met without excessive costs or over-procurement.
- Commit in the near term to developing the CES GHG-emissions reduction framework based on actual energy sales as an extension of the RPS program, using a stakeholder process to develop the details to ensure sufficient incentives to drive new clean resource-build in an affordable manner.
- Coordinate with the CEC to develop a workshop process aimed at ensuring load forecast accuracy at the hourly level by LSE, given the increasing impacts of electrification, large loads, load shifting, DERs, and DR.

[1] Acronyms used in this Summary of Recommendations are defined in the body of this document, *California Community Choice Association's Comments on Administrative Law Judge's Ruling Seeking Comments on Reliable and Clean Power Procurement Program Staff Proposal*, (Rulemaking (R.) 20-05-003 (July 15, 2025).

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Electric Integrated Resource Planning and Related Procurement Processes.	R.20-05-003

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENTS ON RELIABLE AND CLEAN POWER PROCUREMENT PROGRAM STAFF PROPOSAL

California Community Choice Association[2] (CalCCA) submits these comments pursuant to the *Administrative Law Judge's Ruling Seeking Comments on Reliable and Clean Power Procurement Program Staff Proposal*[3] (Staff Proposal), dated April 29, 2025, and the May 14, 2025, *Email Ruling Granting Request for Extension of Time*,[4] extending the time for comments and reply comments in response to the Staff Proposal.

I. INTRODUCTION

Roughly 7,000 megawatts (MW) of new resources must interconnect every year in California between now and 2045 to meet the necessary level of build as set forth in the Senate Bill 100[5] Joint

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2 California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Ava Community Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance of Southern California, CleanPowerSF, Desert Community Energy, Energy For Palmdale's Independent Choice, Lancaster Energy, Marin Clean Energy, Orange County Power Authority, 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 *Administrative Law Judge's Ruling Seeking Comments on Reliable and Clean Power Procurement Program Staff Proposal*, R.20-05-003 (Apr. 29, 2025): https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=565140721.

4 *Email Ruling Granting Request for Extension of Time*, R.20-05-003 (May 14, 2025): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M566/K327/566327214.PDF.

5 Senate Bill 100 (SB 100) (De León, Chapter 312, Statutes of 2018): Bill Text - SB-100 California Renewables Portfolio Standard Program: emissions of greenhouse gases.

Agency Report.[6] This significant undertaking must occur while barriers to bringing new supply online quickly and affordably – including supply chain issues, permitting challenges, interconnection delays, and federal policy changes – continue to create a challenging and unpredictable procurement environment. Experience with procurement orders set forth in Decision (D.) 19-11-016 and D.21-05-035 (i.e., the mid-term reliability (MTR) Order) has demonstrated that procurement ordered on expedited time limits exacerbate these challenges and negatively impact affordability. A new procurement framework is therefore necessary to ensure the Integrated Resource Planning (IRP) process balances reliability, greenhouse gas (GHG) reduction, and customer affordability through orderly and predictable procurement requirements informed well in advance by routine and robust modeling.

CalCCA's comments address the Staff Proposal's advancement of such a framework through the Reliable and Clean Power Procurement Program (RCPPP) proposal, including: (1) two options for addressing reliability needs; and (2) a clean energy standard (CES) proposal to address GHG-reduction needs. _First_, in section II of these comments, CalCCA provides recommendations on an RCPPP policy development *process* aimed at resulting in an effective, durable, and stable RCPPP. CalCCA also recommends exercising caution when considering near-term procurement orders given market constraints impacting the ability to develop new resources in an affordable and timely manner.

Second, in Section III, CalCCA provides recommendations on the *overall direction* the Commission should pursue for RCPPP, including the adoption of a modified reliability Option I framework. CalCCA also recommends the adoption of a CES based on actual energy sales with sufficient conditions to incentivize new clean build.

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6 The *2021 SB 100 Joint Agency Report* finds a build out of roughly 175,000 MW is needed between 2021 and 2045 to meet SB 100 targets. 175,000 MW built over 24 years amounts to roughly 7,000 MW per year. *2021 SB 100 Joint Agency Report* (Mar. 2021) at 10: https://efiling.energy.ca.gov/EFiling/GetFile.aspx?tn=237167&DocumentContentId=70349.

Third, Section IV describes the increasingly critical need for accurate multi-year hourly load *forecasting* at the load-serving entity (LSE) level.

Fourth, Section V responds to the questions put forth in the Staff Proposal.

In summary, CalCCA recommends that the Commission:

- Provide LSEs and developers certainty that their investments will not be undermined by regulatory shifts, given mid to long-term procurement is complex, time consuming, and capital intensive. The Commission should develop RCPPP through a robust stakeholder process that builds an adequate record and establishes a durable and stable procurement framework. The Commission should also carefully consider the practical realities of the current procurement environment (*e.g.,* continued supply chain issues, interconnection delays, and actions at the federal level impacting renewable development) when developing RCPPP and assessing the need for interim procurement requirements prior to RCPPP implementation.
- Develop the reliability and GHG-reduction frameworks on two tracks to thoroughly vet each framework. The first track should develop the reliability framework, targeting implementation in 2029 such that implementation of the RCPPP follows the conclusion of the last MTR order. The second track should develop the CES proposal, which needs additional work to develop the details, targeting implementation for a 2031-2033 compliance period, so that it takes effect following the 2028-2030 RPS compliance period.
- Commit in the near term to developing an RCPPP reliability framework based upon the Staff Proposal's Option I with the following modifications: (1) align RCPPP with the RA program using the SOD methodology; (2) establish the five-year forward showing requirements in alignment with the month-ahead and year-ahead RA processes, with a focus on critical months and hours and reduced percentage requirements in the out years to mitigate against potentially costly over-build resulting from load forecast changes; (3) remove the buffer and CCR in favor of LSE-level risk management and the RA PRM; (4) adopt a penalty waiver process as part of the reliability framework, building upon the "good faith efforts" standard adopted in the MTR decision; and (5) ensure the program is sufficiently transactable so that reliability requirements can be met without excessive costs or over-procurement.
- Commit in the near term to developing the CES GHG-emissions reduction framework based on actual energy sales as an extension of the RPS program, using a stakeholder process to develop the details to ensure sufficient incentives to drive new clean resource-build in an affordable manner.
- Coordinate with the CEC to develop a workshop process aimed at ensuring load forecast accuracy at the hourly level by LSE, given the increasing impacts of electrification, large loads, load shifting, Distributed Energy Resources (DER), and Demand Resource (DR).

II. THE COMMISSION SHOULD ESTABLISH A POLICY DEVELOPMENT PROCESS TO PRODUCE A STABLE RCPPP FRAMEWORK AND CAREFULLY CONSIDER PRACTICAL REALITIES OF THE CURRENT PROCUREMENT ENVIRONMENT

The Commission should develop a durable RCPPP that provides LSEs and developers certainty about the mid- to long-term procurement framework and supports the ability to meet reliability and clean energy objectives in an affordable manner given the practical realities of today's procurement environment. These objectives can be accomplished by: (1) issuing a decision adopting a directional RCPPP framework based on Option I with the modifications described herein and a CES based on actual energy sales; (2) developing RCPPP through a robust stakeholder process in the recently-opened successor IRP proceeding that builds an adequate record and establishes a durable and stable procurement framework; and (3) exercising caution before directing LSEs to enter into contracts for new build between now and the implementation of RCPPP given the numerous constraints on developing new resources in an affordable and timely manner.

A. The Commission Should Establish an RCPPP Stakeholder Process that Allows Sufficient Time to Thoroughly Vet Proposals and Develop a Durable Framework

The Commission should issue a decision adopting a directional RCPPP framework that informs a continued stakeholder process in R.25-06-019 to develop the details of the reliability and GHG-reduction frameworks through at least the end of 2025. On July 2, 2025, the Commission issued an Order Instituting Rulemaking (OIR) to open a new primary venue for oversight of the IRP process. As explained in the OIR, a decision may be issued in R.20-05-003 that adopts an initial framework for the program. If a framework decision is adopted, any further decision making, record development, and implementation would take place in the new IRP proceeding, R.25-06-019. CalCCA welcomes the transition away from ad hoc procurement orders, which are ill-suited to the current procurement environment, to a programmatic approach. A well-designed RCPPP can better balance reliability, GHG reduction, and customer affordability through orderly and predictable procurement requirements informed well in advance by routine and robust modeling.

The development of RCPPP is a significant undertaking that will have substantial implications on LSEs' mid- and long-term procurement activities. Mid- to long-term procurement is complex, time consuming, and capital intensive. LSEs and developers need certainty that their investments will not be undermined by regulatory shifts to enable moving forward with long-term commitments, avoid procurement delays, and support reliability and decarbonization targets. The Commission should therefore develop RCPPP through a robust stakeholder process taken up in R.25-06-019 that builds an adequate record and establishes a durable and stable procurement framework.

The Commission should develop the reliability and GHG-reduction frameworks on two tracks within the new IRP proceeding to allow the Commission and stakeholders to thoroughly vet each framework. Track One should develop the reliability framework, and Track Two should develop the GHG-reduction framework. Given the reliability framework options in the Staff Proposal are considerably more comprehensive than the GHG-reduction proposals, Track One could require less time to complete than Track Two. The Commission should target Track One implementation in 2029, maintaining the phased implementation approach described in the Staff Proposal such that the first RCPPP compliance filing is non-binding and only subject to an administrative penalty for accuracy and timeliness.[7] Track Two and the GHG-reduction, or CES proposal, will need additional work and time to be fully developed. The Commission should therefore target implementation of the CES for a 2031-2033 compliance period, such that it takes effect following the 2028-2030 RPS compliance period.

While these target implementation dates should drive the pace of policy development, the Commission should take the time necessary to fully vet and develop proposals and adjust these targets

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[7] *See* Staff Proposal, at 32.

if necessary. The RCPPP framework must be durable upon implementation. A framework for mid to long-term planning and contracting should not evolve significantly year over year – such regulatory uncertainty adds unnecessary procurement complexity and compliance risk.

B. The Commission Should Carefully Consider Practical Realities of the Current Procurement Environment When Assessing Procurement Needs

CCAs are strong proponents of the clean energy transition and, in many cases, have already gone further in their clean resource procurement than what is required by the RPS program. However, the pace of the clean energy transition must take into account changes in federal policy, the practical realities of contracting, the interconnection process and timeline, and supply chain challenges. Moving too quickly — beyond what is practically possible — will only increase rates for consumers in an already-unaffordable environment.

1. Practical Contracting Realities Need to be Considered When Establishing Procurement Requirements to Ensure Affordability

Today's procurement landscape faces constraints on reaching policy goals outside of the control of LSEs. *First*, the clean energy transition is constrained by the ability to interconnect to the transmission grid. The CAISO has experienced a large backlog of projects across several queue clusters waiting to interconnect, facing lengthy and costly system upgrades, and competing for scarce transmission plan deliverability. *Second*, the electric generation supply chain is facing significant disruptions and cost increases, contributing to project delays. *Third*, recent changes to energy policy at the federal level significantly shift away from prioritizing renewable and clean energy to prioritizing fossil fuel-based resources, reducing clean energy tax credits for utility scale and commercial distributed generation, as well as for residential clean energy projects. These changes may yield impacts on procurement portfolios and the ability to bring new clean resources online in a timely and affordable manner.

Across all Commission-jurisdictional LSEs, progress with contracting for new resources has not kept pace with the Commission's ambitious goals and requirements. The Commission's analysis of December 2023 IRP procurement submittals for the MTR Order and supplemental MTR Order[8] shows a shortfall of 3,581 NQC MW relative to the aggregate obligation.[9] More recent Commission analysis of contracts for resources to come online through the end of 2028[10] similarly shows a deficiency relative to the level of contracting that would align with the 2023 Preferred System Plan (PSP). Beyond existing contracts, LSEs would need to contract with an additional 840 MW of geothermal, 8,500 MW of wind, and 8,300 MW of solar to reach the 2030 PSP portfolio. Averaged over 2029 and 2030, these additional contracts imply a rate of nearly nine gigawatts (GW) per year of new resource additions to align with the PSP.

CalCCA analysis, further described in Appendix A attached hereto, demonstrates that currently contracted resources place California on a solid track to achieve reliable and clean goals, but only under the assumption that retail sales remain flat at 2025 levels. With the 25 percent growth in retail sales included in the CEC's 2024 Integrated Energy Policy Report (IEPR) forecast[11] between 2025 and 2030, however, currently contracted resources may fall short. Currently contracted resources would be expected to achieve only a 45 percent RPS and 58 percent CES, with California Independent System Operator (CAISO) GHG emissions 32 percent higher than 2024 emissions. In

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8 D.23-02-040, *Decision Ordering Supplemental Mid-Term Reliability Procurement (2026-2027) and Transmitting Electric Resource Portfolios to California Independent System Operator for 2023-2024 Transmission Planning Process*, R.20-05-003 (Feb. 28, 2025): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M502/K956/502956567.PDF.

9 CPUC Summary of Compliance with Integrated Resource Planning (IRP) Order D.19-11-016 and Mid Term Reliability (MTR) D.21-06-035 Procurement (Oct. 9, 2024): https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/irp12123compliancereport.pdf.

10 CPUC Resource Tracking Data: Data current as of April 2025: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/summer-2021-reliability/tracking-energy-development/resource-tracking-data-april-2025-release.pdf.

11 CEC 2024 IEPR Demand Forecast for the Planning Scenario: https://efiling.energy.ca.gov/GetDocument.aspx?tn=262820 (see Form 1.1c).

addition, the portfolio of resources would be insufficient by 1,700 MW to meet forecast peak demand and a PRM in September 2030.

Contracting for additional resources to align the 2030 portfolio with the one adopted in the 2023 PSP, however, would likely be sufficient to meet a 65 percent RPS and 79 percent CES target. This would also provide an expected net surplus of more than 3,330 MW in all hours of peak days, even with the load growth embedded in the CEC 2024 IEPR forecast. Under a scenario with no load growth, however, those additional resources simply increase costs to consumers and far exceed the RPS, CES, or GHG emission reduction goals for 2030. CalCCA estimates the incremental net cost of over-procurement under this scenario at $1.0 billion per year.[12] It should be noted that the risk with this additional procurement is the uncertain nature of the forecasted load growth. Between 2020 and 2024, retail sales decreased by three percent. In contrast, the CEC 2024 IEPR projects retail sales will increase by 25 percent between 2025 and 2030, largely due to increased electrification, EVs, and new data centers.[13] In the case that additional contracts are signed to align the 2030 portfolio with the 2023 PSP, but retail sales remain flat out to 2030, the system would far exceed the clean and reliable goals at a significant cost to consumers. The 2023 PSP with flat retail sales would achieve an 82 percent RPS, an 98 percent CES, and emit 9.6 million metric tons (MMT) of CO_2 in 2030.

2. Future Procurement Requirements Should Provide LSEs and Developers the Flexibility to Navigate these Constraints in an Affordable Manner

The recommendations herein seek to develop an RCPPP framework that continues to make progress on the reliability and GHG-reduction targets while providing LSEs and developers the

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12 Net incremental cost is estimated based upon the costs of new resources using Lazard's LCOE (version 18) study less the savings in GHG emissions compliance costs at CARB and the reduction in the fuel cost of natural gas-fired power plants. Additional details and references are included in Appendix A.

13 Increase in retail sales is based on the CEC 2024 IEPR demand forecast for the planning scenario: https://efiling.energy.ca.gov/GetDocument.aspx?tn=262820 (see Form 1.1c). Drivers of the increase in retail sales are described in the CEC Draft 2024 Integrated Energy Policy Report Update (November 2024): https://efiling.energy.ca.gov/GetDocument.aspx?tn=260322&DocumentContentId=96547.

flexibility to navigate these constraints in an affordable manner. These recommendations include: (1) leveraging new and existing resources to meet reliability and GHG-reduction needs; (2) setting the procurement requirement percentages in a manner that enables sufficient flexibility to adjust to changes in load forecast assumptions; (3) providing opportunities for penalty waivers when good faith efforts do not result in a compliant outcome; and (4) ensuring the program is sufficiently transactable to optimize resource portfolios and minimize over-procurement.

Ultimately, whatever reliability and GHG-reduction frameworks the Commission adopts in RCPPP, the Commission should be cautious in directing new build before 2030.[14] Should the Commission order additional procurement in the near-term, any orders must be based on robust need analysis that has been vetted by Staff and stakeholders. Further, if an order is issued, it should also develop a methodology for allocating need based on individual LSE's portfolio, needs, and prior actions rather than simply based on a load ratio share. The Commission should also consider whether to align the order with certain elements of the RCPPP in lieu of past IRP procurement orders, such as whether the order should be assessed based on SOD accounting principles or mELCCs.

III. THE COMMISSION SHOULD COMMIT TO DEVELOPING AN RCPPP THAT RESEMBLES OPTION I WITH MODIFICATIONS, COUPLED WITH A CLEAN ENERGY STANDARD INCENTIVIZING NEW CLEAN BUILD

The Commission should commit to developing an RCPPP that includes: (1) a reliability framework based upon a modified version of Staff Proposal Option I; and (2) a CES program augmented to ensure sufficient incentives for new clean build. The Staff Proposal states the goal of RCPPP as "giv[ing] LSEs a more predictable regulatory framework to procure their share of the resources needed to meet electric system reliability and [GHG] emission reduction goals at least

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[14] During the May 16, 2025, and June 23, 2025, workshops, Energy Division and some stakeholders suggested that an interim procurement order may be necessary depending on the implementation timeline of RCPPP. Additional analysis is needed to demonstrate a reliability need. If a need is identified, the Commission should set the compliance period based upon feasible resource development timelines.

cost."[15] To ensure this goal is met, the reliability and GHG emission reduction frameworks must be evaluated holistically to ensure both reliability and GHG emission reduction objectives are met without being duplicative. Option I, with modifications, plus a robust CES program will ensure that LSEs can optimize their portfolios across new and existing resources to ensure they meet both reliability and GHG-reduction requirements at least cost.

A. The Commission Should Adopt Reliability Option I with Modifications

1. Option I is Superior to Option II

The Commission should pursue the development of the Staff Proposal's reliability Option I, with modifications. Option I encompasses *new and existing resources*, while Option II would implement a *new resource requirement and multi-year RA.* Option I, with modifications as discussed below, is superior to Option II for several reasons. ***First***, Option I is a simpler way to ensure new and existing resources meet reliability targets by avoiding the need to develop and maintain a baseline. Establishing and updating the baseline for the MTR Order has proven to be a complex and error-prone exercise. The administrative burden placed on Energy Division Staff could be avoided by transitioning to a framework that recognizes the reliability contributions of new and existing resources.

Second, Option I accounts for LSEs' prior procurement by accounting for both new and existing resources. Allocating the total reliability need and allowing LSEs to meet the need with both new and existing resources simplifies LSEs' procurement decisions. Specifically, Option I avoids the need for LSEs to time new resource procurement, and potentially delay new resource procurement, simply to meet the definition of "new*.*" In turn, LSEs who procure new resources early will have certainty that their procurement will count towards their share of the reliability need as that need arises. Unlike Option I, Option II could disincentivize early actions to procure. The Staff Proposal's

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15 Staff Proposal, at 1.

definition of the "new" resource vintage for Option II results in LSEs not receiving credit for resources they have procured if the resource is older than 10 years. This will disincentivize early actions by LSEs to procure because they only receive credit for their procurement for 10 years. The need to define what qualifies as a "new" resource could result in delayed procurement because LSEs would need to time their new resource procurement with when they are allocated their share of the new resource requirement. In addition, after a resource reaches 10 years since its commercial operation date (COD), Option II would require LSEs to procure additional new capacity to replace that resource, even if the LSE still has the resource under contract. This could unnecessarily drive up costs for ratepayers, upsetting the balance between affordability and reliability.

Third, by allowing the flexibility to leverage existing resources (including those that can be economically repowered), Option I allows LSEs to optimize their entire portfolios with new and existing resources. While Option I does not have specific new build requirements, Option I using SOD, coupled with the CES framework, can be made robust enough to incentivize new build by all LSEs when appropriate. If new resources in LSE portfolios face project delays, LSEs will still be able to meet their reliability needs under Option I by contracting with existing resources until their new resources can come online. Under Option II, such flexibility is not available for the new resource requirement, meaning even if LSEs face project delays outside of their control and have sufficient existing resources to meet their reliability need, those LSEs will still face penalties. In addition, the new build requirement is based upon significant assumptions around resource retirements and other factors that may or may not materialize. The inability for LSEs to leverage new and existing resources under Option II limits LSEs' ability to adjust to changes in the reliability need as it becomes more certain.

Fourth, Option I enables greater efficiency and consolidation of compliance requirements across various programs, specifically the RA program. As described in section III.A.2.b, below, the

Commission should align RCPPP with the RA program by adopting T+2 through T+4 requirements that flow seamlessly into the T+1 and T+0 RA program. This can be accomplished by setting the need allocation, counting rules, and compliance based upon the SOD framework rather than marginal Effective Load Carrying Capacity (mELCC). For these reasons, the Commission should adopt Option I, with the modifications discussed below.

2. Modifications to Option I are Necessary to Ensure its Adoption Results in a Cost-Effective Reliability Framework

While Option I is superior to Option II, modifications are necessary to ensure Option I results in a cost-effective reliability framework. The Commission should decline to adopt Option II, and Option I should not be adopted without substantive changes. In summary, Option I should be modified to:

- Conduct need allocation, resource accreditation, and compliance in alignment with the RA program using the SOD methodology;
- Establish the five-year forward showing requirements in alignment with the month-ahead and year-ahead RA processes, with a focus on critical months and hours in the out years;
- Reduce the percentage requirements for the out years to address load forecast changes to mitigate against potentially costly over-build;
- Remove the buffer and Collective Capacity Reserve (CCR) in favor of LSE-level risk management and the RA PRM;
- Adopt a penalty waiver process as part of the reliability framework, using the "good faith efforts" standard as a starting point; and
- Ensure the program is sufficiently transactable so that reliability requirements can be met without excessive costs or over-procurement.

These proposed modifications are described in detail below.

a. The Commission Should Align RCPPP with the RA SOD Program

The Commission should align RCPPP with the RA SOD program rather than relying on mELCC. Using one reliability framework for RCPPP and another for RA will increase costs. Fundamentally, adding an additional reliability constraint will never result in a lower total requirement (or cost). Procurement will either bind on mELCC or SOD. In addition, due to the lack of alignment between the two, LSEs cannot optimize for both at once. Any time LSE SOD requirements and mELCC requirements are inconsistent, an LSE's portfolio could comply with one program but not the other. When this occurs, the LSE would either need to procure additional resources or face penalties for non-compliance. Either outcome results in unnecessary excess costs to customers due to a misalignment in mid to long-term requirements in RCPPP and short-term requirements in the RA program. If mELCC is binding, assuming mELCC and SOD both result in reliable outcomes, then paying to meet mELCC compliance adds unnecessary costs.

Even if SOD is always binding, having multiple metrics makes procurement more challenging, and the instability and lack of transparency of mELCC values exacerbates these challenges. The SOD program will be more stable than a mELCC-based program because the exceedance values used for SOD resource counting are based on historical data averaged over several years. While this historical average will vary over time, this variability will be limited as the oldest year's data rolls off and is replaced by the latest data. The SOD profiles can also be developed relatively simply and without the reliance on more complex modeling software, allowing more stakeholders to validate the exceedance values. On the other hand, the Strategic Energy and Risk Valuation Model (SERVM) is a "black box" and sensitive to changes in relatively minor assumptions. A user must be familiar with the model and iterative changes between runs to develop an understanding of what drives model results. This level of understanding is not feasible for all stakeholders to maintain, especially when two presumably reasonable ELCC studies conducted in the same year can have completely different results.[16]

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[16] See, for example, a comparison of 2022 Joint IOU ELCC Study and 2022 IRP Study Update Results for 2030 in the *Petition For Modification of the Joint Utilities to Decision 19-09-043 to Utilize the Results of the Effective Load Carrying Capacity Methodology in the Commission's Integrated Resource Planning Proceeding*, R.18-07-003 (Oct. 14, 2022) at 7: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M497/K737/497737962.PDF.

Shifts in an LSE's total obligation through the PRM, which may occur when using the SOD methodology, are less problematic from a procurement perspective than shifts in the underlying value of resources contracted long-term, which may occur when using the mELCC methodology. A reduction in a procured resource's mELCC could result in an LSE paying first for the procured resource when it did have value, and *again* to procure a different resource to replace the lost value. A change in PRM, on the other hand, would either increase or decrease the overall requirement of the LSE and is unlikely to reduce the value of prior procurement which can occur when using mELCC. Because LSE RA compliance obligations are based on SOD, many LSEs will use SOD as the reliability constraint in their individual modeling. Ultimately, the Commission has established SOD to ensure reliability needs are met through the RA program. The RCPPP should be designed so that mid to long-term procurement sets the system up to meet the reliability needs established in the RA program, which therefore necessitates using SOD for RCPPP.

b. The Commission Should Establish Forward Requirements in Alignment with the Month-Ahead and Year-Ahead RA Processes, with a Focus on Critical Months and Hours in T+3 and T+4

The Commission should establish 10-year forward advisory SOD needs and five-year forward SOD requirements. Needs identified in years T+5 through T+9 would serve as advisory targets to help LSEs begin to plan their procurement further out (*e.g.,* for long lead time resources or hedging of future new clean resource price risk) without putting unnecessary and overly restrictive prescriptions on when LSEs need to make procurement decisions. Requiring binding showings more than five years out forces LSEs to make unnecessarily risky deals with too much uncertainty. Additionally, in the current market where parties are facing supply chain interruptions, import tariffs, and delays to permitting and interconnection, LSEs are finding that having flexibility to adjust their portfolios before locking them in for compliance will aid in getting more resources under contract and online in an affordable manner.

Needs identified in years T+0 through T+4 should be met with binding showings of new and existing resources at increasing percentages of needs as they get closer. Requirement percentages should be set so that LSEs have flexibility to set their own hedging strategies for mid to long-term procurement and to manage their portfolios in light of market conditions. In addition, as described in section IV below, the impacts of electrification and large loads on the load forecast are very uncertain and could result in significant changes in LSEs' requirements as needs become closer in time and the load forecast becomes more certain.

Requirements should not be so high in out-years that LSEs have limited ability to adapt their procurement to account for these changes. The Staff Proposal, which sets the T+2 requirements even higher than the 90 percent T+1 RA requirement, should therefore be modified so that RCPPP requirements do not exceed RA requirements and so that LSEs have the ability to respond to market conditions, manage uncertainty, and optimize procurement.

The Commission should set the T+0 and T+1 requirements consistent with the existing RA requirements, in which LSEs meet 100 percent of their month-ahead requirements and 90 percent of their year-ahead requirements. For T+2 through T+4 requirements, the Commission should require showings in the same months as those used for the year-ahead RA program. The RA program requires year-ahead showings for the summer months, as the most critical months from a reliability perspective. As reliability needs shift, the RCPPP and RA programs could evolve to focus on other critical months. Focusing showings on critical months in later years will help balance the need to align the RA program and RCPPP and limit the complexity of the SOD program.

In addition, T+3 and T+4 showings should focus on critical hours informed by the Commission's need assessment. Requiring 24-hour granularity for binding obligations for out years is unnecessary, overly complicated, and risks inefficiencies, especially as load profiles change. Today, these hours would likely be the net peak hours, but also could evolve as reliability needs shift to other hours.

In summary, the Commission should adopt the compliance requirements advanced in Table 1, below.

Table 1*1*: CalCCA's Proposed Option I Compliance Requirements

Compliance Year	Requirement (%)	Hours	Months
T+0	100	24 Hours	All
T+1	90	24 Hours	Year-Ahead RA Showing Months
T+2	70	24 Hours	Year-Ahead RA Showing Months
T+3	60	Critical Hours	Year-Ahead RA Showing Months
T+4	50	Critical Hours	Year-Ahead RA Showing Months

c. The Commission Should Remove the 2.5 Percent Buffer and CCR From the Reliability Framework

The Commission should not establish a buffer or CCR for RCPPP, and instead rely on LSE-level risk management, a robust compliance enforcement program, and the RA SOD PRM to account for uncertainty. The Staff Proposal includes the buffer and CCR to mitigate two types of uncertainty: (1) development risk; and (2) capacity unavailability and load forecast changes. However, both uncertainties are better accounted for in other ways. *First*, while the buffer is intended to mitigate development risk and other potential causes of insufficient resources being online for LSEs to meet RA requirements,[17] it would be duplicative to actions LSEs already take. LSEs account for risk of

[17] Staff Proposal, at 18.

project delays in their own procurement plans to mitigate against the risk of non-compliance penalties. LSEs are better equipped to mitigate the risk of project delays because how they mitigate this risk will depend upon the projects in their own portfolios. Generic buffers applied to all LSEs will fail to account for the differences in LSE portfolios and the level of COD delay-risks associated with these portfolios.

Second, the CCR is intended to provide "collective insurance" against capacity deficiencies, large changes in total load forecast, or unexpected retirements, effectively duplicating the collective insurance provided by the RA PRM.[18] The RA PRM has long accounted for the "collective insurance" the Staff Proposal describes by accounting for forced outages, load forecast variances, and reserves. The PRM is based upon a one-in-ten loss-of-load expectation (LOLE), an industry-accepted reliability standard. Placing any incremental buffer on top of the RA PRM tends to produce a level of reliability above the one-in-ten LOLE standard with customers paying for a level of reliability that may not be necessary. Requiring an even stricter reliability standard for which there is no demonstrated need will only further exacerbate affordability issues. As LSEs procure to meet SOD needs with a PRM multiple years forward and a CES that requires energy served by increasingly clean supply, the LOLE study will ensure reliability needs are met with the evolving resource mix and result in a PRM that reflects that resource mix. Setting RCPPP reliability requirements based on SOD will ensure the system will meet industry standard reliability targets without an additional buffer or central procurement.

Third, as discussed above, practical contracting realities have created a challenging procurement environment for all LSEs. Adding a buffer and CCR will increase the probability that entities will be unable to comply with the total procurement obligation including the buffer. Including a CCR will place the IOUs in competition with LSEs or obtaining scarce resources. It is unclear if the

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[18] *Id.* at 20.

IOUs will be able to meet their own bundled load needs let alone a CCR. However, if the IOUs can meet their bundled load needs and procure anything toward a CCR, that is competing with all other LSEs efforts to meet their own compliance obligations.

Finally, if LSEs and the IOUs are able to meet the buffer and CCR, the procurement could also lead to significant over-procurement at the expense of customers who already pay some of the highest electric rates in the country. Roughly 7,000 MW of new resources must interconnect every year between now and 2045 to meet the level of build necessary in the SB 100 Joint Agency Report.[19] If LSEs met this target *and* both the buffer and the CCR between now and 2045, California customers would fund 7.7 GW of excess capacity. At the Staff Proposal's estimated net cost of new entry of $15 per kilowatt-month,[20] a single year of this additional expense would amount to $1.386 billion.

In addition, the CCR construct creates an uneven playing field across LSEs by directing the investor-owned utilities (IOUs) to procure the CCR requirement and allocating the costs of CCR procurement to all LSEs. This allows the IOUs to shift resources to and from the CCR and their bundled portfolio, resulting in the IOUs placing their most costly procurement in the CCR and having that procurement paid for by all load. This would include load that is not an energy customer of the IOUs. Provisions that allow the IOU to move resources between meeting their bundled load need and the CCR may protect bundled load customers, but it will always do so at the expense of departed load customers. This gives the IOUs an unfair advantage relative to other LSEs.

Furthermore, MTR progress reports demonstrate uncertainty as to whether an IOU will be more successful at bringing new resources online relative to other LSEs. Indeed, the most recent

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19 The *2021 SB 100 Joint Agency Report* finds a build out of roughly 175,000 MW is needed between 2021 and 2045 to meet SB 100 targets. 175,000 MW built over 24 years amounts to roughly 7,000 MW per year. *2021 SB 100 Joint Agency Report* (Mar. 2021) at 10: https://efiling.energy.ca.gov/EFiling/GetFile.aspx?tn=237167&DocumentContentId=70349.

20 Staff Proposal, at 30.

progress report issued October 9, 2024, for data through December 2023, shows that all LSEs are currently short of meeting their tranche two through five MTR goals, with the IOUs not immune to significant deficiencies.[21]

Table 22: MTR Status for Tranche Two through Five by LSE Type

	Tranche 2			
LSE Type	Obligation	Forecast Online	Excess or deficiency	Percent
IOU	4750	3311	-1439	-30%
CCA	2476	2210	-266	-11%
ESP	773	704	-69	-9%
Total	8000	6225	-1775	-22%

	Tranche 3			
LSE Type	Obligation	Forecast Online	Excess or deficiency	Percent
IOU	5642	5001	-642	-11%
CCA	2939	2968	29	1%
ESP	919	746	-172	-19%
Total	9500	8715	-785	-8%

	Tranche 4			
LSE Type	Obligation	Forecast Online	Excess or deficiency	Percent
IOU	6785	5969	-816	-12%
CCA	3610	3495	-116	-3%
ESP	1104	775	-329	-30%
Total	11500	10239	-1261	-11%

	Tranche 5			
LSE Type	Obligation	Forecast Online	Excess or deficiency	Percent
IOU	7929	6034	-1895	-24%
CCA	4282	4036	-246	-6%
ESP	1289	775	-514	-40%
Total	13500	10239	-2655	-20%

The core function of LSEs is to procure for their customers' electricity needs. Reliance on centralized procurement by the IOUs undermines this function and demonstrably relies on the wrong entities to serve the central procurement function given their MTR procurement track record. Furthermore, in recent years' scarce RA market, the Pacific Gas and Electric Company (PG&E) local

[21] *See* Summary of Compliance with Integrated Resource Planning (IRP) Order D.19-11-016 and Mid Term Reliability (MTR) D.21-06-035 Procurement: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/irp12123compliancereport.pdf. On July 14, 2025, Energy Division served its updated review of LSE procurement progress as of December 2024, which based on CalCCA's analysis, shows similar results: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/compliance-status-reportmid-term-reliability-mtr-and-supplemental-mtr.pdf.

RA central procurement entity (CPE) has not fulfilled its total local RA requirements,[22] and all IOUs have struggled to meet their effective PRM targets.[23] The Commission has historically ordered central procurement for local RA or the effective PRM with no penalty for failing to perform this backstop role. The result is an unlevel playing field still unlikely to produce the desired results. Instead, the Commission should rely on a robust procurement requirement placed on LSEs to meet the needs of their customers that is aligned with the RA SOD PRM coupled with a robust enforcement mechanism to incent compliance and risk management.

For these reasons, the Commission should decline to adopt a generic buffer or a CCR procured by the IOUs and instead rely on a robust enforcement mechanism to incent LSEs to account for the risk of COD delays in their own procurement plans. The Commission should set RCPPP reliability requirements based on SOD to ensure the system will meet industry standard reliability targets without an additional buffer or central procurement.

d. The Commission Should Modify the Reliability Enforcement Framework to Include a Penalty Waiver Process

The Commission should: (1) enforce compliance with T+0 through T+4 by assessing penalties on LSEs who fail to have enough resources under contract to meet their showing requirements; and (2) allow LSEs to apply for a waiver of penalties when, despite reasonable procurement efforts, LSEs cannot meet their requirements at an affordable cost. The Commission is implementing a significant

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[22] *See, e.g.,* Advice Letter 6706-E, *Pacific Gas and Electric Company ("PG&E") Central Procurement Entity ("CPE") Annual Compliance Report* (Sept. 19, 2022), at Public Attachment A – PG&E CPE Aggregate Procurement Summary: https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_6706-E.pdf; *see also* Advice Letter 7027-E, *Pacific Gas and Electric Company ("PG&E") Central Procurement Entity ("CPE") 2023 Annual Compliance Report*, at Public Attachment 2 - PG&E CPE Aggregate Procurement Summary and Additional Reporting (Public Attachment A): https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_7027-E.pdf.

[23] *Workshop on Track 3 Proposals in R.23-10-011*, R.23-10-011 (Feb. 12, 2025), at 51: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/r23-10-011/ra-track-3-workshop-feb-12.pdf.

change in procurement requirements at a time when supply chain challenges, interconnection difficulties, and recent federal policies make new clean resource development increasingly difficult. While the Commission should establish an enforcement mechanism that incents all LSEs to make best efforts to meet their procurement obligations, it should not send the market a signal that it seeks procurement at any cost. The Commission should provide the ability for LSEs to seek a waiver of penalties when circumstances make procurement exceedingly difficult and potentially unaffordable for customers, using the "good faith efforts" standard adopted in the MTR Order as a starting point.[24] The Commission should also seek feedback from LSEs to develop a meaningful waiver process for RCPPP that will balance the need to avoid exorbitant costs with the need to meet reliability targets particularly in the current challenging procurement environment.

e. The Commission Should Ensure the RCPPP is Sufficiently Transactable to Allow Procurement Needs to Be Met in an Affordable Manner

To meet the Staff Proposal's goal of "giv[ing] LSEs a more predictable regulatory framework to procure their share of the resources needed to meet electric system reliability and [GHG] emission reduction goals at least cost,"[25] the program must be sufficiently transactable to allow LSEs to meet reliability requirements without excessive costs or over-procurement. Under CalCCA's proposed reliability framework, Option I modified to include SOD should include the ability for LSEs to trade load obligations on an hourly basis. The current practice of setting hourly RA requirements while prohibiting hourly transactions creates inefficiencies, contributes to over-procurement, and complicates compliance. CalCCA has put forth a comprehensive proposal for hourly load obligation

[24] The MTR order provides for Commission assessment of penalties and potential waivers based on its Resolution M-4846 and consideration of "good faith efforts." D.21-06-035, *Decision Requiring Procurement to Address Mid-Term Reliability* (2023-2026), R.20-05-003 (June 24, 2021), Conclusion of Law 27 (COL) at 93: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603637.PDF.

[25] Staff Proposal, at 1.

trading within SOD in R.23-10-011 to align the granularity of the requirement and the granularity of transactions.[26] The Commission authorized Energy Division to issue a report on transactability issues and the need for hourly load obligation trading in the first quarter of 2026.[27]

Hourly load obligation trading can offer significant cost-savings to ratepayers without negatively impacting reliability. CalCCA's extensive analysis of its members' first binding year-ahead SOD showings demonstrates that hourly load trading could improve RA compliance and reduce RA costs by an estimated $180 million per year.[28] Hourly load trading has the potential to provide these affordability benefits while maintaining LSEs' RA obligations and the RA program's reliability targets. The proposal guarantees that: (1) each LSE's obligation to serve its customers, subject to penalties, remains intact; (2) the associated costs of compliance remain with the original LSE; and (3) the Commission can easily validate that all RA requirements continue to be met without overcounting shown resources. For these reasons, the Commission should adopt Option I modified to align with SOD and ensure the SOD program is sufficiently transactable by allowing LSEs to transact load obligations on an hourly basis.

If the Commission adopts an alternative reliability option to that proposed by CalCCA, other means of transactability will be necessary. For example, under Option II, an LSE that is over-procured for its new resource requirement should be able to be compensated by another LSE for its excess capacity. The Commission has taken steps to allow these types of transactions for the MTR Order if

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[26] *California Community Choice Association's Proposals on Track 3*, R.23-10-011 (Jan. 17, 2025): https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=553679242.

[27] 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 26, 2025), COL 8: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M571/K237/571237404.PDF.

[28] *See California Community Choice Association's Proposals on Track 3*, R.23-10-011 (Jan. 17, 2025), at 8-11; and *Effective Mechanisms for Slice-of-Day RA Trading* (Apr. 24, 2025): https://cal-cca.org/wp-content/uploads/2025/04/4.24.25_Effective-Mechanisms-for-Slice-of-Day-RA-Trading.pdf.

both LSEs trade portions of their compliance obligations.[29] If Option II moves forward, the Commission should allow LSEs to transact portions of their compliance obligations without restricting transactions to those that involve trades of *both* LSEs' obligations to fully enable LSEs to optimize procurement, maximize market efficiencies, and minimize costs.

B. The Commission Should Adopt the CES as the Directional Framework for GHG-Emissions Reduction, and Use the Stakeholder Process to Develop the Framework's Details to Ensure It Adequately Incents Investments in New Clean Build

The Commission should adopt the CES as the directional framework for the GHG-emissions reduction element of RCPPP. CalCCA supports an energy-based model for meeting GHG-emissions reduction targets for several reasons. ***First***, the CES model closely aligns with the design of the RPS program. The RPS program has been successful at driving new renewable resource development. Leveraging the successes of RPS for the CES will ensure RCPPP is also successful at continuing to advance clean energy targets and provide opportunities to consolidate the RPS and CES reporting requirements. ***Second***, the CES model better aligns with the policy established in SB 100 that "…eligible renewable energy resources and zero-carbon resources supply 100 percent ***of all retail sales*** of electricity to California end-use customers and 100 percent of electricity procured to serve all state agencies by December 31, 2045."[30] Other methods of reducing GHG-emissions, like the mass-based approach, may not successfully meet a policy based on achieving retail sales targets because they are based upon forward assumptions rather than actual energy used to serve load. The state's policy goals could be put in jeopardy if the forward assumptions differ too much from reality. ***Third***, the CES model

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[29] *See* D.23-02-040, Ordering Paragraph 10 at 89 ("Any two load serving entities (LSEs) with compliance obligations under Decision (D.) 19-11-016, D.21-06-035, and/or this order may trade compliance obligations in arrangements that may include financial remuneration, but may not result in one LSE being relieved of its entire procurement obligation under D.21-06-035 or this order. Both LSEs must trade portions of their compliance obligations under this provision.").

[30] SB 100 (amending Pub. Util. Code §454.53.(a)): https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100.

is simpler to implement, given its close alignment with the existing RPS program. The Commission should seek to consolidate the CES and RPS programs to allow the Commission to administer a single compliance program for existing RPS and incremental SB 100 goals set out in statute.

The CES is necessary to continue decarbonization progress after 2030, once LSEs have achieved the 60 percent RPS procurement target for the 2028-2030 compliance period. The Commission should seek to implement CES beginning with the 2031-2033 compliance period. In doing so, the Commission should establish an RPS target that must be met with renewable energy credits (RECs), then establish a CES target on top of the RPS target that must be met with either zero emission credits (ZECs) or RECs.

As discussed above, the CES component of the Staff Proposal contains significantly less detail than the reliability component, and the Commission should develop these details with parties through a stakeholder process. This stakeholder process should be used to ensure the CES framework is designed in a manner that adequately incents investment in new clean build and supports an affordable system. To do so, the Commission and parties should consider the following questions:

- How should limits be set on the use of unbundled RECs/ZECs for compliance?
- What long-term commitments for RPS/CES resources are necessary?
- Should LSEs be able to bank ZECs across compliance periods?
- What resources are eligible for ZECs, beyond those already eligible for RPS?

In addition to this stakeholder process, the Commission should host an interagency workshop with the goal of aligning accounting and reporting to reduce administrative burden and streamline reporting across agency programs (such as the RPS program and the CEC's Power Source Disclosure (PSD) program).

IV. THE COMMISSION SHOULD COORDINATE WITH THE CEC TO ESTABLISH A WORKSHOP PROCESS AIMED AT ENSURING LOAD FORECAST ACCURACY AT THE HOURLY LEVEL BY LSE

The Commission should coordinate with the CEC to develop a workshop process aimed at ensuring load forecast accuracy at the hourly level by LSE given the increasing impacts of electrification, large loads, load shifting, DERs, and DR. The RA and IRP processes depend on the CEC's IEPR to forecast load needs. A longer-term planning and procurement framework such as RCPPP will require accurate forecasting of both total system needs *and* hourly needs for each LSE. The CEC's process for using input from individual LSEs to inform the load forecast has thus far resulted in a zero-sum outcome, meaning that if the load forecast of one LSE declines, the forecasts of other LSEs increase in an equal and offsetting manner. The Commission must work with the CEC to determine if the adjustment process currently employed is creating an accurate forecast not only at the system level, but also at the individual LSE level.

Focusing on load forecast accuracy is increasingly important as load forecasts must account for electrification, large loads (including data centers[31]), load shifting, DERs, and DR. Each of these factors can significantly impact the load forecast and must be accurately forecasted to ensure the affordable procurement of reliable and clean power. The Commission should work with the CEC and LSEs to ensure that all critical information necessary for accurate load forecasting is shared in a timely fashion. This is particularly important for load elements that can move quickly, like the energization of

[31] The Commission and CEC's approach to load forecasting should also consider that notwithstanding best efforts, any forecasting is inherently uncertain. This is particularly true for large loads such as data center loads. From the perspective of CCAs in the San Francisco Bay Area, forecasting and buying for data center loads is a particularly challenging issue. The CEC's April 2025, 2024 IEPR planning forecast increased loads for these LSEs almost by a factor of two within five to ten years, including high projections in 2025 even though the LSEs themselves had no evidence of such projects materializing in the near term. Given that data center loads are uncertain and cannot be made more certain even with very careful forecasting, the approach to forecasting and directing procurement for data center load needs to be carefully crafted.

data centers or other large loads. While a one GW data center may represent only about two percent of the CAISO system peak, it could be an incremental peak load increase of 100 percent or more for the single LSE where the data center is located. If information about such loads is not shared as soon as possible with an LSE, it could create significant challenges for the LSE planning and procuring to meet reliability and clean energy goals at reasonable costs. For these reasons, the Commission should begin a workshop process immediately with the CEC, all LSEs, and the IOU distribution planning entities to perfect an accurate forecast process.

V. CALCCA'S RESPONSES TO QUESTIONS IN ATTACHMENT 2 OF THE RCPPP RULING

5.1.1 Reliability Option I vs. Option II

1. Which reliability option (i.e., Option I or Option II) should the CPUC adopt? Please explain the justification for the recommended option in detail.

While neither option is implementable as defined in the Staff Proposal, the Commission should adopt a modified version of Option I. Option I is superior to Option II because:

- Option I is a simpler way to ensure new and existing resources meet reliability targets by avoiding the need to develop and maintain a complex and error-prone baseline, unlike Option II.
- Option I accounts for LSEs' prior procurement actions, unlike Option II which could disincentivize early actions to procure because LSEs would only receive credit for their procurement of new resources for 10 years.
- Option I provides LSEs the flexibility to leverage existing resources (including those that can be economically repowered), allowing LSEs to optimize their entire portfolios as reliability needs evolve with new and existing resources at least cost.
- Option I better enables efficiency and consolidation of compliance requirements across various programs, specifically the RA program if based upon the SOD framework rather than mELCC.

These reasons are expanded upon in detail in section III, above.

2. Currently, Option I and Option II have not explicitly considered imports. How should imports be considered, if at all, in Option I and Option II?

The Commission should allow imports that will be delivered through maximum import capability (MIC),[32] dynamic schedules, pseudo ties, or the subscriber participating transmission owner model to meet reliability needs. Imports will play a critical role in meeting the state's reliability and GHG-reduction objectives, as demonstrated by the Commission's 2025-2026 base portfolio, which includes nine GW of out-of-state wind in 2035.[33] Excluding imports from consideration in RCPPP could force LSEs to rely on more costly in-state alternatives to meet RCPPP compliance requirements. Instead, the Commission should allow imports to count towards RCPPP reliability requirements consistent with the SOD accounting rules for RA imports.

3. In what ways should Option I or Option II be modified prior to CPUC adoption? Are there relevant considerations that are currently not captured in both options?

Option I, while superior to Option II, requires modifications to ensure it results in a cost-effective reliability framework. In summary, Option I should be modified to: (1) conduct need allocation, resource accreditation, and compliance in alignment with the RA program using the SOD methodology; (2) establish the five-year forward showing requirements in alignment with the month-ahead and year-ahead RA processes, with lower percentages to account for uncertainty and a focus on critical months and hours in out years to reduce complexity; (3) remove the buffer and CCR in favor of LSE-level risk management and the RA PRM; (4) adopt a penalty waiver process as part of the

32 The Commission should allow new resources to count without MIC so long as LSEs are making good faith efforts to obtain it, as it has with the MTR Order. Currently, the CAISO only allocates long-term MIC for RA contracts active in the next RA year. Until the CAISO process for allocating long-term MIC changes, LSEs signing long-term power purchase agreements (PPAs) for resources with online dates more than one year in advance will be unable to secure MIC for those resources until the year before the resources come online. The CAISO's RA Modeling and Program Design initiative will reconsider the methodology for allocating long-term MIC.

33 D.25-02-026, *Decision Transmitting Electricity Resource Portfolios to the California Independent System Operator for 2025-2026 Transmission Planning Process*, R.20-05-003 (Feb. 20, 2025), at 19: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M557/K879/557879249.PDF.

reliability framework that builds upon the "good faith efforts" standard adopted in the MTR Order; and (5) ensure the program is sufficiently transactable such that reliability requirements can be met without excessive costs or over-procurement. These modifications are described in detail above.

4. How should Option I or Option II incentivize re-powers?

Re-powers should be eligible to meet RCPPP reliability requirements. Option I implicitly provides incentives for re-powers by accounting for new and existing resources and eliminating the need to establish, track, and maintain a baseline list. Option II risks disincentivizing re-powers of clean resources because new resources as defined would no longer count towards RCPPP requirements after 10 years.

5. Should demand response count towards RCPPP compliance? If so, should it be included in Option I, Option II, or both?

DR should count towards RCPPP compliance under either Option I or Option II consistent with RA rules. Supply-side DR resources should count towards RCPPP compliance up to the maximum cumulative capacity bucket limit established in the RA program and count in the amounts and hours established for SOD. Load modifying DR should be captured in LSE load forecasts. If the RA program changes the treatment of DR in any way, RCPPP should change accordingly.

5.1.2 Alternate Timelines for Reliability Procurement

6. Is the proposed timeline for reliability procurement reasonable, or are there alternate timelines that should be considered?

As described in section II.A above, the Commission should seek to implement the reliability portion of RCPPP in 2029 following the conclusion of the last MTR Order, unless additional time is needed to complete the reliability framework stakeholder process. The reliability procurement timeline should follow the process outlined above, in which the Commission sets the T+0 and T+1 requirements consistent with the existing RA requirements, in which LSEs meet 100 percent of their month ahead requirements and 90 percent of their year-ahead requirements. For T+2 through T+4 requirements, the Commission should require showings in the same months as those used for the year-ahead RA program. For T+5 through T+9, the Commission should allocate indicative needs to LSEs to assist in forward planning but should not require showings for those years.

7. Should compliance filings occur once or twice a year?

Under CalCCA's proposed modified Option I reliability framework, LSEs should make compliance filings consistent with the existing RA compliance filings. Compliance with T+0 requirements should occur monthly 45 days prior to the start of the month, consistent with the existing RA month-ahead process. Compliance with T+1 through T+4 requirements should occur once per year on October 31, consistent with the RA year-ahead process.

Showings for T+1 through T+4 are not needed with biannual precision. Even material changes in contracting status will not affect an LSE's ability to meet the ultimate reliability need. That is, the difference between a contract signed in February or in October of T+0 for T+3 has no impact on the T+3 reliability needs. The Commission should therefore retain the existing once per year cadence used for the year-ahead RA filings for T+1 through T+4 filings.

8. Should enforcement of contracting sufficiency occur once or twice a year?

As described in response to Question 7, under CalCCA's proposed modified Option I reliability framework, LSEs would have to show sufficient contracting with new or existing resources to meet SOD RA requirements monthly for T+0 and annually for T+1 through T+4.[34]

[34] If the Commission adopts Option II, the Commission should not include a contracting sufficiency requirement *and* an online sufficiency requirement for new build requirements. Instead, it should only include an online sufficiency requirement, as it has for the MTR Order. If the Commission retains the contracting sufficiency requirement under Option II, it should be an informational filing only, so that LSEs only face penalties if they do not meet their online requirement.

9. Should enforcement of online sufficiency occur once or twice a year?

As described in response to Question 7, LSEs should have to show compliance with the multi-year SOD requirements on an annual basis as part of their October 31 year-ahead RA filing. For T+1 through T+4 filings, LSEs would be able to show resources that are not yet online, but that are in development, as they do for in-development resources for the existing year-ahead RA process. The T+0 month-ahead filings would require all shown resources to be online, consistent with the existing month-ahead RA process.

5.1.3 To Bound or Not to Bound?

10. Should marginal ELCCs be bound? What are advantages or disadvantages to doing so, if any, in addition to those described in Section 3.1.6.4?

For the reasons described in section III.A.2.a above, the Commission should use SOD for RCPPP rather than mELCC to align with the RA program, minimize costs, and avoid the uncertainty associated with mELCC. If the Commission declines to adopt an RCPPP aligned with the RA program, bounding ELCCs could help provide certainty around the value of different technologies. Bounding ELCCs would mean that the ELCCs would not truly be marginal, however. The ELCC values would have to be vintaged, leading to administrative burden and a potentially inaccurate assessment of how resources contribute to reliability.

11. If marginal ELCCs are to be bound, should the degree of bounding differ between Option I and Option II?

See response to question 10.

5.1.4 Months of Forward Contracting

12. How many months, and which months, should forward contracts include to ensure reliability while minimizing costs if resources can sell to other non-CPUC jurisdictional LSE buyers in other months?

The Commission should set contracting requirements consistent with the existing RA program requirements. That is, the T+0 showings should require 100 percent showings in all months 45 days in advance. The monthly nature of the RA program allows resources to sell to other buyers when they are not needed by Commission-jurisdictional LSEs or allow those resources to conduct planned maintenance in months they are not shown so they can reliably operate when they are needed during critical months.

The T+0 month-ahead showing should set resources' must offer obligations (MOOs), not the T+1 through T+4 showings. The Staff Proposal states, "[t]he filing requirements will include that the contracted or owned resources being used for compliance have a [MOO] for at least the months of the year that Staff find to include the most significant loss of load hours…"[35] This is inconsistent with the way MOOs are established and enforced today within the RA program. The RA program establishes MOOs based upon whether a resource is shown on an LSE's month-ahead RA plan (not the year-ahead RA plan). The CAISO enforces MOOs through bid insertion and RAAIM if the resource is on a monthly RA plan. If LSE contracts required MOOs for resources shown for T+1 through T+4, the total amount of capacity with a MOO may be above and beyond the need of the LSE, exposing those resources not on a monthly RA plan to a cost they otherwise would not have been exposed to but for the RCPPP requirement. If a resource is not needed for a monthly showing, it should not have a MOO so that it can take planned maintenance in months when it is not shown. The RA program establishes requirements to meet load plus a PRM and ensures a sufficient number of resources have a MOO to the CAISO in each month. There is therefore no need to supplement the RA program's established MOO rules with a requirement for resources shown for T+1 through T+4 to have a MOO in all months defined in RCPPP.

As described in section III.A.2.b, the Commission should require T+1 through T+4 showings in critical months consistent with those used for the year-ahead RA requirements. Today, those are the

[35] Staff Proposal, at 25.

summer months, but they could evolve as other months become critical. This evolution should be consistent across the RCPPP and RA programs.

5.1.5 Buffer Percentage

13. How much more reliable should the system be compared to the 1-day-in-10-year LOLE? Is a buffer of 2.5% a reasonable value? If not, what is an appropriate percentage value for the buffer?

For the reasons described in section III.A.2.c above, the Commission should not establish a separate buffer for RCPPP. LSEs account for compliance risk in their own procurement plans, and they are in the best position to do so based upon their knowledge of their own portfolios and associated risks. A well-configured compliance program with penalties will enable LSEs to best manage their own risks. Additionally, the PRM established in the RA program is set based upon the industry accepted standard of 1-in-10 LOLE. Additional buffers on top of those established for RA SOD would have significant affordability implications.

14. How should the affordability impact of the buffer be weighed against its reliability benefit?

See section III.A.2.c above. The industry accepted standard of 1-in-10 LOLE, used for establishing RA SOD requirements, already sets an industry-accepted reliability standard. Any additional buffer would be applying a stricter standard and adversely impact affordability.

15. Should the buffer apply to both Option I and Option II? Why or why not?

For the reasons described in response to Question 13 and 14, a buffer (beyond the RA SOD PRM) should not apply to Option I or II.

16. Should the buffer percentage differ between Option I and Option II? Why or why not?

For the reasons described in response to Question 13 and 14, a buffer (beyond the RA SOD PRM) should not apply to Option I or II. The Commission should decline to adopt a generic buffer and instead rely on a robust enforcement mechanism to incent LSEs to account for the risk of COD delays in their own procurement plans. The Commission should also set RCPPP reliability requirements based on SOD to ensure the system will meet industry standard reliability targets without an additional buffer or central procurement.

5.1.6 CCR Percentage

17. At what percentage should the CCR be set?

As described in section III.A.2.c above, the Commission should not establish a CCR for the same reasons the Commission should not set a buffer. In addition, the CCR: (1) allows IOUs to shift the most risky and/or costly procurement from their bundled portfolio to the CCR with limited Commission oversight; (2) undermines the core function of LSEs, which is to procure resources to serve their customers electricity needs; and (3) relies on the IOUs, who have not proven to be more successful at procuring new resources relative to other LSEs.

18. Is the range of 1.5% to 3% of the initial RPN appropriate? If not, what is an appropriate range?

For the reasons described in section III.A.2.c, the Commission should not establish a CCR. Establishing a CCR on top of the SOD RA PRM could result in over-procurement at a significant cost to customers.

19. Should the CCR percentage differ between Option I and Option II? Why or why not?

For the reasons described above, there should not be a CCR for Option I or Option II.

5.1.7 Incorporating Centrally Procured Resources

20. Which option, as presented in Table 11, is better for incorporating new eligible centrally procured resources into RCPPP? What are additional pros and cons of each option?

Any RCPPP design should be designed to drive procurement *by LSEs* of generation needed to serve their respective communities, rather than CPEs. CCAs are already advancing the achievement of the state's climate goals with leadership at the local level. State statute recognizes this in Public Utilities Code section 366.2(a)(5), which provides:

> A community choice aggregator shall be solely responsible for all generation procurement activities on behalf of the community choice aggregator's customers, except where other generation procurement arrangements are expressly authorized by statute.

Allowing LSEs to make their own procurement decisions, as opposed to prescribing procurement of specific technologies through a central buyer, will allow the market to pursue the most cost-effective projects that possess the right attributes to meet reliability and GHG-reduction targets. The Commission should therefore seek to limit central procurement as part of RCPPP in favor of individual LSE procurement.

The Commission should allow LSEs to count their share of any past or future centralized procurement towards both their reliability requirements and GHG-reduction requirements. The Commission should utilize the stakeholder process proposed in section II.A to develop the process for accounting for centrally procured resources. Neither Option A nor Option B would address all the issues surrounding the potential procurement of long-lead time resources by the California Department of Water Resources. The Commission and stakeholders need to consider: (1) how to provide LSEs with sufficient time to know how much central procurement they are allocated; (2) the instance in which CPE procurement falls through and how the Commission would address that shortfall without shifting the development risk of CPE procurement onto LSEs; (3) the process for substituting a centrally procured resource that goes on outage; and (4) how to ensure attributes are sufficiently transactable by LSEs to allow them to optimize their portfolios and minimize the risk of over-procurement.

5.2 GHG Reduction Questions

5.2.1 Approaches to GHG Reduction

1. Should existing IRP and RPS processes be used or modified to achieve the electric sector's GHG emissions reduction goals instead of a new CES framework? If so, why?

As described in section III.B above, the CES is necessary to continue decarbonization progress post-2030, once LSEs have achieved the 60 percent RPS procurement target. The CES should be consolidated into the RPS compliance program to enable a single compliance program for GHG-reduction focused policy goals.

2. Should the CPUC adopt the Clean Energy Standard and create Zero-Emission Credit (ZEC) instruments as proposed by Staff with or without modifications?

The Commission should adopt the CES as the directional framework for GHG-reduction. An additional stakeholder process is necessary to further develop the details of the Staff Proposal, as described in section III.B above. In summary:

- The CES is necessary to continue decarbonization progress after 2030, once LSEs have achieved the 60 percent RPS procurement target for the 2028-2030 compliance period. The Commission should seek to implement CES beginning with the 2031-2033 compliance period.
- The Commission should seek to consolidate the CES and RPS programs to allow the Commission to administer a single compliance program for existing RPS and incremental SB 100 goals set out in statute.
- The Commission should establish an RPS target that must be met with RECs, then establish a CES target on top of the RPS target that must be met with either ZECs or RECs.
- A stakeholder process should be used to ensure the CES framework is designed in a manner that adequately incents investments in new clean build and supports an affordable system. To do so, the Commission and stakeholders should consider the following questions:
    - How should limits be set on the use of unbundled RECs/ZECs for compliance?
    - What long-term commitments for RPS/CES resources are necessary?
    - Should LSEs be able to bank ZECs across compliance periods?
    - What resources are eligible for ZECs, beyond those already eligible for RPS?

In addition to this stakeholder process, the Commission should host an interagency workshop with the goal of aligning accounting and reporting to reduce administrative burden and streamline reporting across agency programs (e.g., the CEC's PSD program).

3. What considerations should be taken into account to ensure that all RECs and ZECs used for CES compliance would align with how CARB regulates GHG emissions in its Mandatory Reporting Regulation (MRR) and GHG Emissions Inventory?

The Commission should seek to avoid replicating reporting requirements already in place for the existing MRR and PSD programs.

4. Which zero-carbon resources should be eligible for the CES?

As a starting point, the Commission should align CES eligibility with the existing and updated RPS and PSD definitions of renewable and zero-carbon resources, based on rulemaking activities at the CEC and the California Air Resources Board (CARB). The stakeholder process should consider what other zero-carbon resources should be eligible based on definitions adopted at other energy agencies to ensure consistency across compliance programs.

5. Are there alternative approaches to GHG reductions that should be considered and why?

No, the Commission should adopt the CES proposal as a directional framework, with the modifications described herein, and conduct a stakeholder process to develop the details of the framework.

6. Should the CPUC further develop a GHG reduction approach through a certain forum (e.g., workshops)? How could guardrails be implemented so that LSEs continue to procure toward future GHG targets while gathering more stakeholder input on an effective and efficient GHG framework?

Yes, as described in section III.B, the CES framework needs additional development through a stakeholder process. In addition to this stakeholder process, the Commission should host an interagency workshop with the goal of aligning accounting and reporting to reduce administrative burden and streamline reporting across agency programs (*e.g.,* the CEC's PSD program). The existing RPS program will ensure continued progress on GHG-reduction, through 2030. The Commission should seek to implement the CES program to allow it to be incorporated into the RPS program beginning with the 2031-2033 compliance period.

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,

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

July 15, 2025

APPENDIX A
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENTS ON RELIABLE AND CLEAN POWER PROCUREMENT PROGRAM STAFF PROPOSAL

Existing 2030 Goals Threatened on Current Trajectory -
Added New Build Requirements Would Pressure Constrained Market

To evaluate progress toward meeting clean and reliable goals by 2030, California Community Choice Association (CalCCA) developed a simple load and resource table and slice-of-day (SOD) stack analysis. The load and resource table evaluates clean energy goals by comparing estimates of annual generation of different resources to retail sales. The SOD stack analysis evaluates reliability goals by comparing the potential contribution of resources toward meeting hourly demand and a planning reserve margin on the peak day of each month. Findings from the analysis are presented first, with details of the data and assumptions provided after in the Approach section.

1. Findings:

The resources currently contracted by the California Public Utilities Commission (CPUC)-jurisdictional entities, assuming no additional contracted resources come online after 2028, are insufficient to meet the clean and reliability goals with the load growth embedded in the California Energy Commission (CEC) 2024 Integrated Energy Policy Report (IEPR) forecast to 2030. Without additional new resources, the contracted resources achieve only a 45 percent Renewables Portfolio Standard (RPS) and a 58 percent clean energy standard (CES), and emissions increase to 53.5 million metric tons (MMT) of CO2 per year, 32 percent higher than the 2024 emissions. The resources would fall short of meeting the planning reserve margin by about 1,700 MW in September 2030.

Scenario	Current Trajectory	Forecasted Load with PSP Build	Flat Load with PSP Build
Load Forecast	CEC 2024 IEPR	CEC 2024 IEPR	Remains at 2025
Build	Current Contracts	2023 PSP	2023 PSP
Reliability	1,700 MW Short	3,300 MW Surplus	9,600 MW Surplus
RPS (% retail sales)	45%	65%	82%
CES (% retail sales)	58%	79%	98%
GHG (MMTCO2/yr)	53.5	32.3	9.6

Table 1. Reliability and Clean Outcomes in 2030 for Alternative Scenarios of Resource Build and Load Growth

Contracting with additional new resources to align the 2030 portfolio with the portfolio adopted in the 2023 Preferred System Plan (PSP) would meet both the reliability and clean goals by 2030 under the CEC 2024 IEPR load forecast. Beyond the currently contracted resources, aligning with the 2023 PSP requires an additional 840 MW of geothermal, 8,500 MW of wind, and 8,328 MW of solar. Assuming that these additional resources are brought online by 2030, the portfolio would achieve a 65 percent RPS, a 79 percent CES, and California Independent System Operator (CAISO) emissions would fall to 32.3 MMT CO2. From a reliability perspective, the portfolio would meet the planning reserve margin with a net surplus of at least 3,300 MW in all hours.

The risk with this additional procurement, however, is the uncertain nature of the forecasted load growth. Between 2020 and 2024, retail sales decreased by three percent. In contrast, the CEC 2024 IEPR projects retail sales will increase by 25 percent between 2025 and 2030, largely due to increased electrification, electric vehicles, and new data centers. In the case that additional contracts are signed to align the 2030 portfolio with the 2023 PSP, yet retail sales remain flat out to 2030, the system would far exceed the clean and reliable goals at a cost to consumers. The 2023 PSP with flat retail sales would achieve an 82 percent RPS, a 98 percent CES, and emit 9.6 MMT CO2 in 2030.

2. Approach:

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Retail Sales (TWh/yr)	202.1	199.6	204.1	196.7	196.2	199.9	205.1	212.6	225.7	237.7	249.8
Thermal + Unspecified Imports (TWh/yr)	128.0	127.0	124.8	104.8	100.1	96.7	90.5	92.9	103.4	116.7	130.0
Renewable (TWh/yr)	60.5	66.9	69.2	74.7	86.0	90.1	102.0	107.8	111.7	111.7	111.7
Large Hydro +Nuclear (TWh/yr)	30.6	26.5	30.8	39.6	39.0	33.3	33.3	33.3	33.3	33.3	33.3
RPS (% retail sales)	30%	34%	34%	38%	44%	45%	50%	51%	49%	47%	45%
CES (% retail sales)	45%	47%	49%	58%	64%	62%	66%	66%	64%	61%	58%
GHG (million mTCO2)	49.6	53.2	53.1	44.0	40.6	39.8	37.2	38.2	42.5	48.0	53.5

Table 2. Example Load and Resource Table for the Current Trajectory with Currently Contracted Resources and the CEC 2024 IEPR Load Forecast

The above analysis is based on a simple load and resources table, similar to Table 1. This table uses retail sales from the CEC 2024 IEPR forecast and includes only currently contracted resources reported by the CPUC.

The primary assumptions and data sources for the load and resource table are:

- Retail sales are the total sales for the CAISO region using the CEC 2024 IEPR Planning forecast.[36]
- Energy from Large Hydropower and Nuclear uses aggregate generation reported by the CAISO[37] for 2020-2024. Generation in 2025-2030 is assumed to be the average of the historical generation over 2020-2024, implying no additional capacity or retirements.

36 CEC IEPR 2024 load forecast.

37 CAISO Production and Curtailments Data: https://www.caiso.com/library/production-curtailments-data.

- Energy from wind and solar is the aggregate of the post-curtailment generation reported by the CAISO[38] plus additional estimated generation from contracted wind and solar reported by the CPUC.[39] The CPUC only reports contracts through 2028, implying no additional new resources are contracted between 2028 and 2030. Generation from contracted resources assumes a 35 percent pre-curtailment capacity factor for wind and 30 percent pre-curtailment capacity factor for solar. This generation is derated by a two percent curtailment rate for new wind and eight percent curtailment rate for new solar. These curtailment rates were estimated from the incremental wind or solar curtailment between 2020 to 2024 as a percentage of the pre-curtailment incremental energy over the same period.

- Energy from Biomass, Small Hydro, and Geothermal in 2020-2024 is based on the CAISO reported "Renewable" generation less wind and solar.[40] Generation in this category is expected to increase from contracted geothermal[41] assuming an 80 percent capacity factor and no additional curtailment.

- Losses[42] for 2020-2024 are calculated as the difference between the aggregate generation and imports for the CAISO region[43] and the CEC's reported retail sales for CAISO.[44] The loss rate for 2025-2030 is assumed to be the average loss rate over 2020-2024.

- Energy from Thermal and Unspecified Imports for 2020-2024 is from CAISO data. For 2025-2030, we assume that the total thermal and unspecified imports is the difference between the retail sales plus losses and the generation from all other sources.

- GHG emissions in 2020-2024 are reported by CAISO.[45] We assume the average emissions rate of the Thermal and Unspecified Imports over 2020-2024 (0.411 metric tons of CO2 per MWh) continues over 2025-2030. Changes in the energy from Thermal and Unspecified Imports, calculated above, result in changes to the CAISO-wide GHG emissions.

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[38] *Ibid.*

[39] CPUC Resource Tracking Data as of April 2025: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/summer-2021-reliability/tracking-energy-development/resource-tracking-data-april-2025-release.pdf.

[40] CAISO Production and Curtailments Data: https://www.caiso.com/library/production-curtailments-data.

[41] CPUC Resource Tracking Data as of April 2025: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/summer-2021-reliability/tracking-energy-development/resource-tracking-data-april-2025-release.pdf.

[42] Losses are calculated as non-storage generation and imports less retail sales. Using this approach implies losses include transmission and distribution losses plus round-trip efficiency losses from battery storage.

[43] CAISO Production and Curtailments Data: https://www.caiso.com/library/production-curtailments-data.

[44] Actual retail sales (as opposed to forecast retail sales) are extracted from the year prior to the year of the IEPR forecast vintage for retail sales in 2020-2023. For example, the 2022 actual retail sales are reported in the 2023 IEPR vintage. All CEC IEPR forecast vintages were downloaded from the CEC. Retail sales for 2024 are an estimate, rather than actual, and are obtained from the CEC 2024 IEPR forecast.

[45] CAISO Greenhouse Gas Emission Tracking Report, December 2024: https://www.caiso.com/documents/greenhouse-gas-emissions-tracking-report-december-2024.pdf.

To assess reliability in 2030, CalCCA concurrently developed a SOD stack analysis using the following assumptions:

- Hourly load on peak days each month is from the CEC 2024 IEPR forecast for the Planning Scenario.[46] In addition to demand, resources must meet a planning reserve margin of 18 percent in each month of the year, consistent with the PRM adopted in the RA program for 2026.[47] The RA program also extends authorization of IOUs to procure additional resources beyond the PRM. We assume that this excess IOU procurement requires an additional 1,260 MW of resources, which is the lower end of the authorized excess procurement.
- Resources that contribute to the SOD RA program are a combination of the existing resources in the current net-qualifying capacity (NQC) List published in the CPUC's Master Resource Database,[48] and contracted resources tracked by the CPUC.[49] Hourly exceedance profiles for wind and solar are included within the Master Resource Database.
- RA Imports for each month are set to the observed RA import levels from 2024,[50] with an hourly shape based on the import RA shape used by the CPUC in their 2025 SOD stack analysis.[51]
- CalCCA further adjusted the supply of resources to account for thermal derates, IOU retention for substitution, and resources in the NQC list contracted by the Department of Water Resources for the Strategic Reliability Reserve. These assumptions are consistent with the approach previously described by CalCCA elsewhere.[52]

To estimate the incremental cost of additional contracting to align with the 2023 PSP, CalCCA assumed the following:

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46 Hourly CAISO forecast for the CEC 2024 IEPR.

47 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): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M571/K237/571237404.PDF.

48 CPUC Resource Adequacy Compliance Materials: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/slice-of-day-compliance-materials/mrd-final-2025_05102025v2.xlsx.

49 CPUC Resource Tracking Data as of April 2025: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/summer-2021-reliability/tracking-energy-development/resource-tracking-data-april-2025-release.pdf.

50 RA import data downloaded from oasis.caiso.com as "Import Capability Used in RA Plan Data".

51 CEC, *Summer Energy Reliability Workshop* (May 2, 2025), at 114-116: https://efiling.energy.ca.gov/GetDocument.aspx?tn=262897&DocumentContentId=99547.

52 *California's Constrained Resource Adequacy Market: Ratepayers Left Standing in a Game of Musical Chairs* (Jan. 16, 2925): https://cal-cca.org/wp-content/uploads/2024/02/CalCCA-Stack-Analysis-2023-2026-updated-01_16_24-.pdf.

- The nameplate capacity of the additional resources beyond the currently contracted resources is the difference between the 2023 PSP in 2030[53] and the contracted resources through 2028 reported by the CPUC.
- The cost of the contracts uses the average Levelized Cost of Energy (LCOE) of geothermal, wind, and solar reported by Lazard in the LCOE report (version 18).[54] This LCOE is multiplied by the pre-curtailment energy generated each year by the new resources, where the energy calculations use the same assumptions as noted above in the load and resources table. In aggregate, the new contracts cost $3.5 billion per year.
- The new contracts reduce the fuel and emissions of Thermal and Unspecified imports, based on the post-curtailment energy. The fuel costs use EIA's 2025 Annual Energy Outlook (AEO)[55] 2030 forecast of natural gas prices for 2030 and a 7,750 MBTU/MWh heat rate implied by the average 0.411 metric tons of CO2 per MWh emissions rate calculated above. The emissions costs assume the GHG permit price stays at the 2030 floor price for the Cap-and-Trade market of $36.59/metric ton CO2.[56] Based on these assumptions, the new contracts reduce fuel and emissions costs by $2.4 billion per year.
- The net incremental cost is the difference between the contract cost of $3.4 billion per year and the avoided fuel and emissions cost of $2.4 billion per year. With these assumptions, the net incremental cost of the new contracts is $1.0 billion per year.

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53 D.24-02-047, *Decision Adopting 2023 Preferred System Plan and Related Matter, and Addressing Two Petitions for Modification*, R.20-05-003 (February 15, 2024): Table 4: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M525/K918/525918033.PDF.

54 Lazard Levelized Cost of Energy+ Report (version 18, June 2025). https://www.lazard.com/news-announcements/lazard-releases-2025-levelized-cost-of-energyplus-report-pr/.

55 Annual Energy Outlook 2025 Table 3. Energy Prices by Sector and Source. Case: Reference case | Region: Pacific. https://www.eia.gov/outlooks/aeo/.

56 CEC. California Energy Demand 2023 GHG Allowance Price Scenarios. https://efiling.energy.ca.gov/GetDocument.aspx?tn=254569&DocumentContentId=89994.

California Community Choice Association

SUBMITTED 07/16/2025, 03:24 PM

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

1. Please provide your organization's comments on any other items that should be considered for IPE 5.0.

The California Community Choice Association (CalCCA) appreciates the opportunity to comment on the California Independent System Operator's (CAISO's) Interconnection Process Enhancements (IPE) 5.0 Scoping Document. IPE 2023 made transformative changes to the interconnection process to address the flood of projects seeking to interconnect to the CAISO system in support of the state's policy goals. CalCCA appreciates the CAISO's undertaking IPE 5.0 to continue to make incremental improvements to the interconnection process.

Specifically, CalCCA supports the CAISO's commitment to revisiting the ability for operational energy-only (EO) projects to re-enter the interconnection process to be studied and to seek deliverability. While IPE 2023 policy prohibits EO projects in Cluster 15 and later from seeking a deliverability allocation, there are legitimate reasons why projects may pursue interconnection via the EO process, such as a willingness on the part of both developers and load-serving entities (LSEs) to contract for a period of time for EO deliveries.[1] At the same time, CalCCA understands and supports the CAISO's intent of preventing developers from utilizing the EO pathway to circumvent a competitive deliverability allocation process.

If a project enters the queue and comes online as EO, the project should be allowed to submit a *new* interconnection request and follow the intake and study process for obtaining deliverability. This approach could help expand and expedite opportunities for developers to finance and construct projects without a deliverability allocation while ensuring projects cannot circumvent the interconnection intake process, in which projects seeking deliverability and projects seeking EO are scored separately. Constructed and operational projects are more viable than earlier-stage projects under development and therefore may offer more affordable and timely pathways for additional deliverable supply. Especially at the current time, when there is a critical need for more affordable and deliverable capacity, these projects should be allowed to compete against other projects in the interconnection intake process and deliverability allocation process to contribute to the state's resource adequacy (RA) requirements.

To avoid an EO resource from unduly benefitting from its EO status, the new interconnection queue request for deliverability should be evaluated using all the criteria that the CAISO has developed. In doing so, demonstration of a PPA should require the capacity element of the resource (i.e., RA) and not the existing EO contract that it had previously signed. The stakeholder process should also consider a reasonable limit on the number of times that an EO resource can seek deliverability, with a reasonable length of time between study requests, to ensure that the resources do not unnecessarily congest the queue and prevent more competitive resources from being studied.

In summary, projects that have achieved commercial operation as EO should be allowed to submit new interconnection requests, apply for deliverability allocation, and be scored along with all other projects seeking deliverability.

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[1] For example, the EO pathway has been used to get projects online in time to comply with grant timelines for grant-funded projects.

California Community Choice Association

SUBMITTED 07/16/2025, 03:47 PM

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

1. Please provide a summary of your organization's comments on the Mixed-Fuels & Distribution-Level Resources Discussion Paper and June 30, 2025 working group meeting:

The California Community Choice Association (CalCCA) appreciates the opportunity to comment on the California Independent System Operator's (CAISO's) Mixed Fuels and Distribution-Level Resources Discussion Paper (Discussion Paper) and the June 30, 2025, Working Group Meeting. In summary, the CAISO should:

- Establish the following principle when determining which drivers of bid cost recovery (BCR) warrant uplift payments to storage resources: (1) if the resource did not recover its costs due to scheduling coordinator (SC) action, uplift payments *are not* warranted; and (2) if the resource did not recover its costs due to CAISO market action, uplift payments *are* warranted.
- Continue monitoring the proposed revision request (PRR) 1627 changes to ensure no unintended consequences arise during the challenging summer months;
- Provide direct guidance on high-sustainable limit (HSL) formulation to ensure high-quality HSL data submittal to ensure the CAISO has accurate estimates of instantaneous generating capacity of variable energy resources;
- Develop a fair default energy bid (DEB) for hybrid resources given the underlying resource component characteristics and cost structures;
- Seek to provide operational certainty and reduce the administrative burden of dynamic limit tool use;
- Obtain additional transparency on distribution-level storage and their charging constraints using a Master File flag as a first step; and
- Request that the Department of Market Monitoring (DMM) monitor the use of distribution-level storage charging and discharging constraints to ensure the distribution provider is allocating these constraints in an equitable manner.

2. Provide your organization's comments on Uplift: Current Drivers for Storage Resources, including your organization's perspective on each of the drivers identified and whether they should warrant uplift:

The CAISO identified seven drivers for storage BCR and asks stakeholders to opine on whether these drivers warrant an uplift payment. When determining which drivers warrant uplift, the CAISO should establish the following principle: (1) if the resource did not recover its costs due to SC action, uplift payments *are not* warranted; and (2) if the resource did not recover its costs due to CAISO market intervention, uplift payments *are* warranted.

Therefore, if the current storage BCR design results in uplift payments because of SC action (*e.g.,* self-scheduling, uninstructed deviation, bidding behavior), then these uplift payments are likely not warranted and the CAISO should consider how to prevent them in the new storage BCR design. If the current BCR design results in uplift payments because of CAISO intervention in the market (*e.g.,* some instances of market power mitigation,[1] CAISO market intervention, other things outside the SC's control), then uplift payments are likely warranted and should be retained in the new storage BCR design. The CAISO should also seek to develop a storage BCR design that mirrors the treatment of other similarly situated resources, such as multi-stage generators, to the extent feasible.

The CAISO and stakeholders will need to identify the circumstances that define a CAISO market intervention warranting BCR. For example, the multi-interval optimization could dispatch a resource based upon non-binding prices in a way that makes the resource worse off. Does this constitute a CAISO market intervention where BCR is warranted? Or is it a product of market optimization, for which generators are at risk for profit maximization?

The CAISO should also provide data on whether the current multi-interval optimization generally benefits or harms battery storage resources. This is important in determining whether SCs can rely upon the optimization without BCR or if the optimization is expected to result in lost revenues that necessitate BCR.

[1] Market power mitigation will be a difficult topic as the bid may be from a storage resource to preserve its output until a later time while complying with a must-offer obligation through RA but may also be rightfully mitigated to avoid the abuse of market power. If it is the abuse of market power that makes the difference between being profitable and taking a loss, BCR would not be warranted.

3. Provide your organization's comments on DMM's presentation:

CalCCA has no comments on DMM's presentation at this time.

4. Provide your organization's comments on Terra-Gen's presentation:

CalCCA has no comments on Terra-Gen's presentation at this time.

5. Provide your organization's comments on NextEra's presentation:

CalCCA has no comments on NextEra's presentation at this time.

6. Provide your organization's comments on Monitoring of PRR 1627 changes (SOC Management and FRU):

CalCCA appreciates the CAISO's efforts to enhance the state-of-charge calculation to consider flexible ramping product awards to prevent negative price formation and reliability outcomes. CalCCA also supports continued monitoring of the PRR 1627 changes to ensure no unintended consequences arise during the challenging summer months.

7. Provide your organization's comments on High Sustainable Limit

CalCCA supports the CAISO providing direct guidance on HSL formulation to ensure high-quality HSL data submittal to ensure the CAISO has accurate estimates of instantaneous generating capacity of variable energy resources.

8. Provide your organization's comments on Market Power Mitigation & Default Energy Bids for Hybrid Resources:

CalCCA supports developing a DEB for hybrid resources such that they can be subject to market power mitigation like other resources and CAISO's stated objective of developing a fair hybrid DEB given the underlying resource component characteristics and cost structures.

9. Provide your organization's comments on Dynamic Limits and Ancillary Services:

CalCCA supports the CAISO's goal of providing operational certainty and reducing the administrative burden of dynamic limit tool use.

10. Provide your organization's comments on Distribution-Level Charging Constraints:

Because distribution provider-imposed charging and discharging restrictions on distribution-level storage may impact the CAISO's ability to dispatch them, the CAISO needs additional transparency on these resources and their constraints. A Master File flag identifying distribution-level storage, as the CAISO proposes, is a good first step in providing this transparency.

In addition, the DMM should monitor the use of distribution-level storage charging and discharging constraints to ensure the distribution provider is allocating these constraints in an equitable manner. DMM could accomplish this by assessing which SC's distributed resources are affected and unaffected by constraints and at what frequency to ensure they are comparable across SCs.

11. Provide other topics, challenges, or opportunities related to mixed-fuel and/or distribution-level resources that should be discussed:

CalCCA has no comments at this time.

12. Provide your organization's comments on the prioritization of Mixed-Fuel and Distribution-Level Resources topics, relative to other topics in the Storage Design and Modeling initiative.

CalCCA has no comments at this time.

13. Please provide any additional comments:

CalCCA has no additional comments at this time.

July 22, 2025

VIA ELECTRONIC MAIL (EDTARIFFUNIT@CPUC.CA.GOV)

California Public Utilities Commission
Energy Division
Attention: Tariff Unit
505 Van Ness Avenue, 4th Floor
San Francisco, CA 94102

Re: California Community Choice Association's Protest of the Joint Utilities' Pending Loads Implementation Advice Letter Pursuant to D.24-10-030

Dear Energy Division Tariff Unit,

Pursuant to the California Public Utilities Commission's (Commission's) General Order (GO) 96-B,[1] the California Community Choice Association[2] (CalCCA) submits this protest of Southern California Edison Company (SCE) Advice 5567-E, San Diego Gas & Electric Company (SDG&E) Advice 4676-E, Pacific Gas and Electric Company (PG&E) Advice 7630-E, the Joint Utilities' Pending Loads Implementation Advice Letter Pursuant to D.24-10-030, submitted on June 27, 2025[3] (Advice Letter). The Advice Letter was submitted in accordance with Ordering Paragraph (O¶) 12 of Decision (D.) 24-10-030 (the Decision).[4] CalCCA protests the Advice Letter pursuant to section 7.4.2 of GO 96-B, including: subsection (2), which allows protests when the relief requested is not authorized by statute or Commission order; subsection (3), which allows protests on the grounds that the analysis in the advice letter contains material errors or omissions; and subsection (6), which allows protests on the grounds the relief requested in the Advice Letter is unjust, unreasonable, or discriminatory.

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1 References to "General Rules" are to the general rules identified in General Order 96-B.

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 *Joint Utilities' Pending Loads Implementation Advice Letter Pursuant to D.24-10-030*, Rulemaking (R.) 21-06-017, June 27, 2025: https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_7630-E.pdf.

4 D.24-10-030, *Decision Adopting Improvements to Distribution Planning and Project Execution Process, Distribution Resource Planning Data Portals, and Integration Capacity Analysis Maps*, Rulemaking (R.) 21-06-017 (Oct. 17, 2024): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M544/K154/544154869.PDF.

I. INTRODUCTION

The Decision requires PG&E, SCE, and SDG&E (collectively, the IOUs) to create a pending loads category in the Distribution Planning and Execution Process (DPEP) and file a Tier 3 advice letter (AL):

1. Proposing the method for developing the pending loads category and incorporating the category into the Distribution Planning Process;
2. Defining the types of information considered in the pending loads category and the general criteria applied to each category; and
3. Discussing the risk of pending loads that do not materialize and how to mitigate the risk.[5]

The Advice Letter includes each IOU's pending loads implementation proposal as Attachments A (PG&E), B (SDG&E), and C (SCE).

CalCCA supports the IOUs' efforts to create pending loads frameworks to better align the DPEP with the California Energy Commission's (CEC) Integrated Energy Policy Report (IEPR) forecast and reduce energization times, consistent with the above requirements. However, CalCCA protests certain aspects of the pending loads frameworks proposed by the IOUs, both collectively and individually.

As set forth in detail below, CalCCA recommends that the Commission:

- Require the IOUs to adopt consistent processes for: (1) determining confidence levels of pending loads; (2) applying discount factors; and (3) determining the criteria for exceeding the IEPR forecast;
- Require SDG&E to modify its pending loads categorization framework to include different confidence levels and data types;
- Limit the IOUs' use of studies to inform pending loads and disallow their use for exceeding the IEPR forecast;
- Require PG&E to establish additional guardrails for its use of hot spot locations;
- Require SDG&E to develop a methodology for linking pending loads with known loads;
- Reject PG&E's and SCE's proposals to bypass regulatory approvals to modify their pending loads frameworks or types;

5 D.24-10-030, O¶ 10, at 193, and O¶ 12, at 194.

- Require the IOUs to provide details on how they plan to align transmission-interconnected pending loads with other planning processes;
- Require the IOUs to include community choice aggregators (CCAs) in their data reporting proposals for large loads; and
- Require SDG&E to respond to and incorporate stakeholder feedback in its pending loads implementation framework.

II. PROTEST

A. The Commission Should Require the IOUs to Adopt Consistent Processes for Determining Confidence Levels of Pending Loads, Applying Discount Factors, and Determining the Criteria for Exceeding the IEPR Forecast

The Commission should require the IOUs to adopt consistent processes and factors for determining pending loads confidence levels, applying discount factors, and determining criteria for exceeding the CEC's IEPR forecast. This will ensure potential new customers are treated fairly, simplify regulatory oversight, and provide greater ratepayer protection. As currently proposed, the IOU pending loads frameworks would result in widely varying growth projections and grid investment planning. Consistency across the IOUs' pending loads frameworks balances affordability with proactive planning to serve new loads while minimizing energization delays.

To illustrate this point, PG&E categorizes local government plans as high confidence, allowing pending loads derived from these plans to exceed the IPER forecast, although it is unclear whether PG&E would apply a discount factor.[6] SCE, on the other hand, considers these plans to be in the lowest confidence category, meaning they would not be allowed to exceed the IEPR forecast, and a discount factor would be applied to this load.[7] Furthermore, SCE's plan mentions applying a discount factor of up to 30 percent,[8] while PG&E states that it "does not propose to apply a set "discount" to individual Pending Loads based on its confidence level, instead categorizing the loads based on its confidence level and applying the guardrails described herein."[9] SDG&E's proposed framework does not include confidence levels or discount factors; instead, it compares its own localized forecast to the IEPR and adopts the greater of the two forecasts.[10]

If an identical pending load type were evaluated under each IOU's proposed framework, the resulting forecasted load could be very different, along with the timing and magnitude of necessary grid improvements. Customers seeking to energize new loads must be treated fairly

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6 Advice Letter, Attachment A, Table 2, at 4.
7 *Id.*, Attachment C, Framework Summary Table, at 3.
8 *Id.*, note 1, at 6.
9 *Id.*, Attachment A, footnote 12, at 8.
10 *Id.*, Attachment B, at 1.

and equally, regardless of the IOU service territory in which they are located. Likewise, ratepayers in one IOU service area should not be burdened with higher rates because their IOU's framework allows for more aggressive growth projections than another IOU's framework. The Commission should therefore require the IOUs to standardize their categorization of pending loads types including a clear common definition for each pending load category, the application of consistent discount factors, and the ability to exceed IEPR forecasts with strong supporting evidence.

B. The Commission Should Require SDG&E to Modify Its Pending Loads Categorization Framework to Include Different Confidence Levels and Data Types

SDG&E should be required to modify its pending loads framework to include separate categories based on different confidence levels and data types. Unlike PG&E and SCE, SDG&E's approach does not provide a transparent, structured categorization of pending loads by confidence level, nor does it include a discussion about discount factors for less certain data types. Instead, SDG&E defines pending loads solely as the difference between its own bottom-up forecast and the IEPR forecast.[11] By omitting confidence levels for various types of pending loads data and not using discount factors to account for uncertainty, SDG&E risks over-investing in grid upgrades at ratepayers' expense.

SDG&E's proposal focuses on medium-duty and heavy-duty transportation electrification loads. This overly narrow focus could miss significant growth of other emerging loads, such as building electrification and data centers, leaving it underprepared to meet infrastructure needs and customer expectations. SDG&E states that it may develop pending loads for other categories in the future, but has not yet defined methodologies or criteria.[12] The Commission should require SDG&E to modify its pending loads framework to include distinct categories based on different confidence levels for different data types to accommodate load growth from transportation and building electrification, similar to PG&E's and SCE's proposals.

C. The Commission Should Limit the Use of Studies to Inform Pending Loads and Disallow Their Use for Exceeding the IEPR Forecast

The Commission should limit the use of studies as a source of information on pending loads. Studies should be used to inform disaggregation of IEPR forecasted loads, rather than as justification for exceeding the IEPR forecast. All of the IOUs propose using information from high-confidence studies,[13] or studies based on customer data or regulatory compliance obligations, as a basis for exceeding IEPR forecasts.[14] Regardless of the type of study or source

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11 *Ibid*.
12 *Id*., at 4.
13 *Id*., Attachment C, at 6-7.
14 *Id*., Attachment A, at 7.

of the data used, reliance on studies as justification to exceed the IEPR forecast creates uncertainty, reduces transparency, and should be limited.

In its informal comments on the pending loads workshop, the Public Advocates Office (Cal Advocates) correctly points out that "[t]he IEPR provides a forecast that is a robust foundation for distribution planning because the forecast is transparent, is developed with interagency coordination, and allows for substantial stakeholder feedback."[15] Cal Advocates describes its review of the IOUs' data sources and studies, expressing "concerns about the lack of transparency and the level of confidence of the studies,"[16] concluding "this lack of transparency undermines oversight by the Commission and review by parties."[17] Finally, rather than relying on study information to exceed the IEPR forecast, Cal Advocates recommends that the IOUs "submit any such studies to the CEC in order to allow the CEC to use the studies as a basis for the CEC's IEPR forecast."[18] CalCCA shares Cal Advocates' concerns and urges the Commission to limit the IOUs' use of studies and rely instead on customer-specific information as the basis for exceeding the IEPR forecast.

D. The Commission Should Require PG&E to Establish Additional Guardrails for Its Use of Hot Spot Locations

The Commission should require PG&E to establish additional guardrails for its use of hot spots. PG&E defines a "hot spot" as "a specific geographical area with forecasted load growth from *multiple* sources (e.g., historical growth trends, Known Loads, customer energization projects, community plans, regulatory requirements, study results)."[19] This broad definition gives PG&E significant flexibility to designate a hot spot. As proposed by PG&E, a pending load must typically meet all of the minimum criteria to be placed in a given category, unless it is in a designated hot spot. For a pending load located in a hot spot, PG&E has significant discretion to categorize that pending load into any given criteria as long as just one of the criteria is met. Without additional guardrails, PG&E's unilateral use of hot spots could undermine transparency and increase the risk of overinvestment in grid upgrades that may not materialize. The Commission should therefore require stakeholder input on the record to inform the definition, identification, and designation of hot spot locations.

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15 *The Public Advocates Office's Informal Comments on the Pending Loads Workshop Report*, R.21-06-017 (May 1, 2025), at 2.
16 *Id*., at 6.
17 *Ibid*.
18 *Id*., at 7.
19 *Id*., Attachment A, at 5.

E. The Commission Should Require SDG&E to Develop a Methodology for Linking Pending Loads with Known Loads

The Commission should require SDG&E to develop a methodology for accurately associating pending loads with known loads, as required in D.24-10-010.[20] SDG&E states that its methodology does not allow pending loads to be linked to actual customer energization requests or known loads.[21] The absence of this linkage makes it impossible to assess the following requirements from O¶ 14 of D.24-10-030:[22]

- The portion of pending loads that eventually became energization requests;
- The load size or timing deviations between pending and known loads;
- The differences in the accuracy and usefulness of pending loads by end use category, information sources, or methodology; and
- The expected in-service date of projects initiated due to the pending loads category.

Without a straightforward method for linking pending and known loads, it is challenging to attribute infrastructure investments to pending loads. This fundamentally undermines the Commission's and stakeholders' ability to assess the accuracy or usefulness of pending loads as required by D.24-10-030. It also reduces transparency and accountability for how ratepayer dollars are spent. The Commission should require SDG&E to develop a methodology for tracking pending loads and associating them with known loads to support transparency and accountability.

F. The Commission Should Reject PG&E's and SCE's Proposals to Bypass Regulatory Approval for Modifying Their Pending Loads Frameworks or Types

The Commission should not allow PG&E and SCE to bypass the regulatory approval process for adopting modifications to their pending load frameworks or pending load types. PG&E and SCE stated that certain regulatory approvals are unnecessary once the Commission approves their proposals.[23] Adopting a pending loads category may allow better alignment between the IOUs' distribution planning and IEPR forecasts and potentially reduce energization timelines. However, the pending loads category also creates a risk for overinvestment in grid upgrades that may not materialize. Therefore, regulatory approvals, informed by stakeholder input, are necessary. The regulatory approval process will also provide transparency to stakeholders and ratepayers regarding the IOUs' distribution planning process changes and

20 Decision, O¶ 14, at 194-195.
21 Advice Letter, Attachment B, at 4.
22 Decision, O¶ 14, at 194-195.
23 Advice Letter, Attachment A, at 13, and Attachment C, at 9.

impact. This is especially the case given pending loads have never been tested or implemented previously.

1. PG&E's Proposal to Bypass Regulatory Approvals Should be Rejected

PG&E should clarify the difference between adjustments or methodological changes and fundamental changes to the pending loads framework. PG&E states that it "does not anticipate any further regulatory approval to adjust the [pending loads] framework."[24] It further states that it "will inform the Commission of methodological or procedural changes in the pending loads category via its annual reporting on pending loads."[25] However, the annual reporting is not subject to approval, and stakeholders will not be able to oppose changes or provide feedback to the Commission on any future adjustments. Such a process would give PG&E complete control over the methodological changes it chooses to implement.

Further, PG&E proposes that the IOUs be allowed to "individually file a Tier 2 Advice Letter requesting modifications to the approved Pending Load Framework if they deem fundamental changes to the Framework are required."[26] PG&E does not define or provide examples of any fundamental changes to which it refers. Although there is value in administrative simplicity, potential changes to the pending loads framework, even if methodological, could have implications for customers seeking energization. Such changes could also have financial consequences for ratepayers, who ultimately pay for the investment decisions the pending loads inform. PG&E's proposal to eliminate stakeholder vetting and Commission approval removes a necessary guardrail for protecting ratepayer interests and should be rejected.

2. SCE's Proposal to Bypass Regulatory Approvals Should be Rejected

SCE states that regulatory approvals for new types of pending loads will be required, stating:

> Once the Commission approves this proposal, no additional regulatory processes will be needed to approve new pending load types since the categories and criteria are designed to incorporate additional pending load types – either based on customer project plans or based on new studies – that are not yet developed.[27]

However, SCE does not define what pending load type means. The Framework Summary Table included in SCE's pending loads proposal lists several data sources, with specific

24 *Id*., Attachment A, at 13.
25 *Ibid*.
26 *Ibid*.
27 *Id*., Attachment C, at 9.

examples in each category's definition.[28] It is unclear if SCE refers to data categories, data sources, or the examples listed under the definition for each category when it refers to data type. Nevertheless, there is a great deal of subjectivity in determining what studies are considered high or medium confidence level, which will impact whether it can be used to exceed the IEPR forecast. Since the process of determining confidence levels and discount factors for pending loads has never been tested, the Commission should err on the side of caution and require approval before the IOUs change their approved frameworks or pending loads types.

G. The Commission Should Require the IOUs to Provide Details on How They Plan to Align Transmission-Interconnected Pending Loads with Other Planning Processes

The Commission should require the IOUs to describe how they will align planning for transmission-interconnected pending loads with their DPEP and with the California Independent System Operator's Transmission Planning Processes (TPP). While the IOUs' pending loads framework proposals focus on the distribution level, very large pending loads may seek to interconnect at the transmission level, which could have downstream impacts on the distribution grid. D.24-10-030 requires alignment in the use of pending load data in the DPEP and other planning processes, including the TPP.[29] IOUs have not addressed how they intend to incorporate transmission-interconnected pending loads into their distribution and transmission planning processes, which is necessary for understanding the full impacts of pending loads on both the DPEP and TPP.

The IOUs' pending loads framework proposals should therefore be modified to describe how large loads interconnecting at the transmission level will impact transmission or distribution planning. PG&E is the only IOU that addressed pending load alignment with other planning processes in its proposed framework. Rather than specifying how large pending loads interconnecting at the transmission level will impact the DPEP and TPP, PG&E states that the "reconciliation of local disaggregated forecasts (including known loads) with transmission and system level forecast already occurs."[30] PG&E further states that it "will leverage existing processes for coordination of aggregated distribution forecasts with transmission planning to create the annual base case model."[31] The Commission should require the IOUs to describe in their proposed frameworks:

- In which process (DPEP, TPP, or both) the IOUs plan to incorporate transmission-interconnected pending loads;

28 *Id.*, at 3.
29 Decision, O¶ 11, at 193.
30 Advice Letter, Attachment A, at 14.
31 *Ibid.*

- How the IOUs plan to align pending loads at both the distribution and transmission levels with other planning processes;
- Whether pending load data for projects expected to interconnect directly at the transmission level will be allowed to exceed the IEPR forecast; and
- Whether the large load interconnection request example included in PG&E's proposed Category A includes large loads interconnecting directly at the transmission level.

H. The Commission Should Require the IOUs to Include CCAs in Their Data Reporting Proposals for Large Loads

The Commission should ensure that CCAs can access customer usage and project data on large pending loads, including confidential data redacted from annual public reporting on pending loads. As the default generation service provider for customers within their service areas, CCAs are entitled to customer information pursuant to statute and rules established by the Commission, and CCAs must have timely information on large pending loads to enable cost-effective procurement to serve those loads. CCAs must have access to large pending load information to meet long-term resource adequacy and reliability procurement planning needs. CCAs, similar to IOUs, must gain access to the large pending load information well in advance which will be critical for CCAs to meet their procurement needs. Both PG&E's and SCE's pending loads implementation plans discuss customer pending loads data confidentiality needs, but fail to include CCAs among the list of agencies entitled to this data.

PG&E states that, because of the 15/15 Rule, most of the customer pending load data they report may be marked confidential, and thus redacted. It clarifies that "confidential data can still be provided under a Non-Disclosure Agreement or other statutory conditions to stakeholders with access to such data."[32] Similarly, SCE cites Commission mandates to keep customer usage data confidential, but says that "[c]ertain entities, such as Energy Division staff and Cal Advocates, may access this confidential data."[33] SDG&E does not address data confidentiality in its pending loads plan.

In D.12-08-045, the Commission made additional determinations concerning CCAs' access to and responsibility for customer information, making clear that such access and use is on par with that of the IOUs.[34] Therefore, CCAs should have access to all customer- and project-specific data, including the customer name, project location, forecasted in-service date, expected capacity, load type, pending load category, and information source. The Commission should

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[32] *Id.*, Attachment A, at 10.
[33] *Id.*, Attachment C, at 8.
[34] D.12-08-045, *Decision Extending Privacy Protections to Customers of Gas Corporations and Community Choice Aggregators, and to Residential and Small Commercial Customers of Electric Service Providers*, R.08-12-009 (Aug. 31, 2012), at 4-5, and 23-26.

therefore affirm CCAs' existing rights to this data, and require the IOUs to make this data available to CCAs in a timely fashion without redaction, anonymization, or aggregation in recognition of CCAs' roles as generation service providers.

I. The Commission Should Require SDG&E to Respond to and Incorporate Stakeholder Feedback in Its Pending Loads Implementation Framework

The Commission should require SDG&E to provide substantive responses to stakeholder feedback from informal comments submitted on May 1, 2025, and incorporate this feedback in its pending loads implementation framework. The Advice Letter describes requests from The Utility Reform Network and CalCCA for SDG&E to: (1) provide specific data sources and confidence levels; (2) offer greater transparency into forecasting methods; and (3) clarify how pending loads relate to distribution planning and investment.[35] SDG&E's responses dismiss these concerns and fail to incorporate substantive improvements to its framework in response to this stakeholder input. The Commission should require SDG&E to provide specific responses to stakeholder input, including listing data sources and confidence levels that stakeholders can review to determine the reasonableness of its assumptions.

III. CONCLUSION

For the reasons described above, CalCCA respectfully requests the Commission:

- Require the IOUs to adopt consistent processes for: (1) determining confidence levels of pending loads; (2) applying discount factors; and (3) determining the criteria for exceeding the IEPR forecast;
- Require SDG&E to modify its pending loads categorization framework to include different confidence levels and data types;
- Limit the use of studies by the IOUs to inform pending loads and disallow their use for exceeding the IEPR forecast;
- Require PG&E to establish additional guardrails for its use of hot spot locations;
- Require SDG&E to develop a methodology for linking pending loads with known loads;
- Reject proposals of PG&E and SCE to bypass regulatory approval for modifying their pending loads frameworks or types;
- Require the IOUs to provide details on how they plan to align transmission-interconnected pending loads with other planning processes;
- Require the IOUs to include CCAs in data reporting proposals for large loads; and

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35 *Id.,* Attachment B, at 3-5.

- Require SDG&E to respond to and incorporate stakeholder feedback in its pending loads implementation framework.

CalCCA thanks the Energy Division for its review of this protest and for considering the relief requested.

Respectfully submitted,

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

Leanne Bober

Leanne Bober,
Director of Regulatory Affairs and
Deputy General Counsel

cc via email:
PGETariffs@pge.com
GAnderson@sdge.com
SDGETariffs@sdge.com
AdviceTariffManager@sce.com
Karyn.Gansecki@sce.com
Service List: R.21-06-017

July 22, 2025

VIA ELECTRONIC MAIL (EDTARIFFUNIT@CPUC.CA.GOV)

California Public Utilities Commission
Energy Division
Attention: Tariff Unit
505 Van Ness Avenue, 4th Floor
San Francisco, CA 94102

Re: California Community Choice Association's Protest of San Diego Gas & Electric Company, Southern California Edison Company, and Pacific Gas and Electric Company Tier 3 Advice Letter Proposing a Framework for Implementation of Scenario-Based Planning Pursuant to Ordering Paragraph 8 of D.24-10-030

Dear Energy Division Tariff Unit,

Pursuant to the California Public Utilities Commission's (Commission) General Order (GO) 96-B,[1] the California Community Choice Association[2] (CalCCA) submits this protest of San Diego Gas & Electric Company (SDGE) (Advice 4675-E), Southern California Edison Company (SCE) (Advice 5566-E), and Pacific Gas and Electric Company (PG&E) (Advice 7631-E) Tier 3 Advice Letter Proposing a Framework for Implementation of Scenario-Based Planning submitted on June 30, 2025[3] (Advice Letter). The Advice Letter was submitted in accordance with Ordering Paragraph (O¶) 8 of Decision (D.) 24-10-030 (the Decision).[4] CalCCA protests the Advice Letter pursuant to section 7.4.2 of GO 96-B, including: subsection (2), which allows protests when the relief requested is not authorized by statute or Commission order; subsection (3), which allows protests on the grounds that the analysis in the advice letter contains material errors or omissions;

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1 References to "General Rules" are to the general rules identified in General Order 96-B.

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 *San Diego Gas & Electric Company, Southern California Edison Company, and Pacific Gas and Electric Company Tier 3 Advice Letter Proposing a Framework for Implementation of Scenario-Based Planning Pursuant to Ordering Paragraph 8 of D.24-10-030*, Rulemaking (R.) 21-06-017 (June 30, 2025): https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_7631-E.pdf.

4 D.24-10-030, *Decision Adopting Improvements to Distribution Planning and Project Execution Process, Distribution Resource Planning Data Portals, and Integration Capacity Analysis Maps*, Rulemaking (R.) 21-06-017 (Oct. 17, 2024): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M544/K154/544154869.PDF.

and subsection (6), which allows protests on the grounds the relief requested in the Advice Letter is unjust, unreasonable, or discriminatory.

I. INTRODUCTION

The Decision requires PG&E, SCE, and SDG&E (collectively, the IOUs) to implement the use of scenario planning in the Distribution Planning and Execution Process (DPEP) and file a Tier 3 advice letter that, among other things:

1. Proposes a framework for the implementation of scenario-based planning; and
2. Identifies the steps to be taken to facilitate the transition to using scenarios and a timeline for using them in the 2026 Distribution Planning Process (DPP) cycle.[5]

The Advice Letter includes each IOU's scenario planning framework proposal as Attachments A (PG&E), B (SDG&E), and C (SCE).

CalCCA supports the IOUs' efforts to create scenario planning frameworks to better align the DPEP with the California Energy Commission's (CEC) Integrated Energy Policy Report (IEPR) forecast and reduce energization times, consistent with the above requirements. However, CalCCA protests certain aspects of the scenario planning frameworks proposed by the IOUs, both collectively and individually as set forth below.

CalCCA recommends that the Commission:

- Require the IOUs to develop demand flexibility scenarios for the 2026–2027 DPP cycle that explores options for mitigating future grid upgrades;
- Require the IOUs to track and report on least-regrets investments for which the anticipated load did not materialize, and the disposition of any unused assets;
- Limit the ability of pending loads derived from studies to inform the IOUs' investment strategies;
- Require SDG&E to incorporate pending loads into its proposed scenario planning process and prepare high and low scenarios based on confidence level categories;
- Reject PG&E's proposal to bypass regulatory approval for modifying its scenario planning framework and for identifying planned investments incremental to the base scenario; and
- Require the IOUs to include community choice aggregators (CCA) in their data reporting proposals for large loads.

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5 *Id.*, O¶ 6, at 191, and O¶ 8, at 192.

II. PROTEST

A. The Commission Should Require the IOUs to Develop Demand Scenarios for the 2026–2027 DPP Cycle that Explores Options for Mitigating Future Grid Upgrades

The Commission should require the IOUs to develop demand flexibility scenarios for the 2026 – 2027 DPP cycle that explore the potential for reducing the need and costs of future grid upgrades. Demand flexibility is a valuable tool that can be leveraged to reduce investments in grid upgrades and lessen ratepayer impact, yet the IOUs make only vague commitments to incorporate it in future scenario plans. As the electrification of the transportation and building sectors accelerates, it is imperative to leverage all available tools to mitigate ratepayer impacts, especially in the midst of the current rate affordability crisis. Demand flexibility should be evaluated as a non-wires alternative to conventional grid investments, and not treated as a static variable layered onto a load forecast, to ensure ratepayers receive the maximum benefit.

During the question-and-answer session after SCE's presentation at the April 22, 2025, Scenario Planning Workshop, Energy Division staff expressed the need for demand flexibility to be modeled in the scenario plans so ratepayers can see the benefits from deferred grid investments.[6] Both SCE's and PG&E's scenario planning proposals state that they cannot yet model demand flexibility, but may do so in the future. SCE's proposal states:

> Processes for locationally targeted deployment or procurement of demand flexibility are not yet well-defined and mature. As these processes develop, SCE may incorporate demand flexibility within the suite of mitigation options.[7]

PG&E's proposal states:

> Currently, load management and load flexibility are based upon current modeling capabilities and the IEPR (e.g., inclusion of [time-of-use] rates in [electric vehicle] load profiles). However, as the availability of load flexibility and load management on the distribution grid increases, and PG&E develops load flexibility modeling capabilities for use in Distribution Planning, PG&E anticipates that this increased load flexibility will be incorporated directly into the Base Scenario.[8]

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[6] Scenario Planning Workshop Recording, R.21-06-017 (Apr. 22, 2025), at hour 2:24:17: https://www.youtube.com/watch?v=Fi2uEALDvHA.
[7] Advice Letter, Attachment C, at 4.
[8] *Id.*, Attachment A, at 2.

PG&E further states that the "Low Scenario will also include consider [sic] enhanced, speculative load management that could occur in the future,"[9] but notes that "[d]ue to limitation of PG&E's current tools, PG&E will not be able to consider load management in the low scenario until the 2026-27 forecasting cycle."[10]

SDG&E includes no mention of demand flexibility in their proposal, except to state that it may consider a Scenario 2 in future years that incorporates "the potential use of alternative load forecast components from the CEC's IEPR (e.g., a low load management impact scenario were the CEC to produce such a scenario in a future IEPR)."[11] Rather than viewing demand flexibility as a potential mitigation option, SDG&E appears to take the opposite approach and view it as a risk to be avoided.

The Decision requires the IOUs to prepare a load flexibility DPP Assessment (Assessment) to be incorporated into the Electrification Impact Study Part 2 (EIS Part 2).[12] The Decision further directs the IOUs to describe how the study meets the Assessment's requirements from the Staff Proposal to Improve the DPEP (Staff Proposal).[13] The Staff Proposal states that the goal of the Assessment "is to better enable utilities to strategically incorporate load management and load flexibility techniques into their distribution planning and provide transparency and an opportunity for stakeholder input on how utilities are planning to accomplish this goal."[14] The Staff Proposal provides the following rationale for their recommendation:

> Given the magnitude of electrification-related load expected, flexible loads are going to be a resource of significant scale in the medium- to long-term with the potential to mitigate substantial distribution infrastructure cost.[15]

The January 2025 Ruling proposed modifying the due date for filing the final EIS Part 2 Report to December 29, 2025, to ensure the outcomes inform the 2026-2027 DPP cycle.[16] CalCCA recommends that the Commission require the IOUs to develop a demand flexibility scenario in the

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9 *Id*., at 3.
10 *Ibid*.
11 Advice Letter, Attachment B, at 1.
12 Decision, O¶ 19, at 197-198.
13 *Id*., O¶ 20, at 198.
14 *Staff Proposal for the High DER Proceeding*, R.21-06-017 (Apr. 5, 2024), at 82: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M529/K078/529078850.PDF.
15 *Ibid*.
16 *Assigned Commissioner's and Assigned Administrative Law Judge's Ruling Seeking Comment on Proposed Modifications to the Due Dates to File the Final Electrification Impact Study Part 2 Report*, R.21-06-017 (Jan. 22, 2025), at 1: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M555/K183/555183947.PDF.

2026-2027 DPP cycle that explores the potential for mitigating future grid upgrades based on the results of the final EIS Part 2 Report.

B. The Commission Should Require the IOUs to Track and Report on Least-Regrets Investments for Which the Anticipated Load Did Not Materialize, and the Disposition of Any Unused Assets

The Commission should require the IOUs to track and report on any least-regrets investments related to proactive grid upgrades for which the anticipated load did not materialize and the disposition of unused, underutilized, or repurposed assets. The IOUs' proposed frameworks include strategies that identify early investments for long lead time upgrades, such as procuring land, sourcing equipment, and obtaining permits to reduce energization delays. While CalCCA supports proactive planning and grid investments to reduce energization delays, adequate guardrails must be implemented to protect against overinvestment if the IOUs' forecasts are incorrect or the load fails to materialize.

PG&E's proposed framework includes a Base Scenario, which includes Category A and B Pending Loads, that "will serve as the primary basis for identifying Grid Needs and designing solutions (i.e., Planned Investments)."[17] PG&E further explains that these two categories of pending loads allow it to "proactively plan for any long lead time projects, meet customer's energization needs, and address "Hot Spots" of expected electrification growth, while ensuring proper guardrails for ratepayers."[18] Finally, its High Scenario "will be used to adapt (e.g., resize) and drive efficient use of mid-term and long-term investments," but will not form the basis for any new planned investments.[19]

SCE states its "primary objective is to reduce the lead time of future investments while maintaining flexibility to adapt to changing load forecasts, thus minimizing risks to higher costs."[20] Its Base and High Scenarios will inform future grid investments, "while preserving the ability to defer or accelerate projects as conditions evolve."[21]

Finally, the results of SDG&E's Scenario 1 assessment "will determine whether any adjustments to the upstream distribution capacity upgrades identified in the Base Scenario are warranted."[22] SDG&E states that it will incorporate any such adjustments in the 2026 Grid Needs Assessment and Distribution Upgrade Project Report.[23]

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17 Advice Letter, Attachment A, at 2.
18 *Ibid*.
19 *Ibid*.
20 *Id*., Attachment C, at 5.
21 *Id*., at 5-6.
22 *Id*., Attachment B, at 2.
23 *Ibid*.

The proactive identification of future grid needs and least-regrets investment planning will likely help reduce delays from long lead time upgrades, as the IOUs suggest in their respective scenario planning framework proposals. However, appropriate guardrails must also be implemented to protect ratepayers from assuming the risks of investments for which the anticipated load does not materialize. The IOUs must be held accountable for investment decisions based on more speculative long-term load growth estimates. The Commission should therefore require the IOUs to track and report on any longer-term, least-regrets investments to ensure the IOUs make prudent grid investments and minimize overinvestment risks.

C. The Commission Should Limit the Ability of Pending Loads Derived from Studies to Inform the IOUs' Investment Strategies

The Commission should limit the ability of pending loads derived from studies to inform the IOUs' investment strategies. Each of the IOUs propose using information from high- and medium-confidence pending loads studies to inform their investment strategies.[24] Regardless of the type of study or source of the data used, reliance on studies as justification to exceed the IEPR forecast creates uncertainty, reduces transparency, and increases the risk of overinvestment in grid upgrades. For these reasons, pending loads derived from studies should not be used to inform short-term investment plans. However, pending loads derived from studies can instead be used to disaggregate the IEPR forecast for medium- and long-term investment plans, so long as they do not exceed the IEPR forecast.

In its informal comments on the Pending Loads Workshop Report, The Public Advocates Office at the California Public Utilities Commission (Cal Advocates) correctly points out that "[t]he IEPR provides a forecast that is a robust foundation for distribution planning because the forecast is transparent, is developed with interagency coordination, and allows for substantial stakeholder feedback."[25] It describes Cal Advocates' review of the IOUs' data sources and studies, expressing "concerns about the lack of transparency and the level of confidence of the studies,"[26] concluding "this lack of transparency undermines oversight by the Commission and review by parties."[27] Finally, Cal Advocates recommends that the IOUs "submit any such studies to the CEC in order to allow the CEC to use the studies as a basis for the CEC's IEPR forecast."[28]

CalCCA shares Cal Advocates' concerns and urges the Commission to disallow the use of pending loads derived from studies to exceed the IEPR forecast and rely instead on customer-specific information as the basis for exceeding it. The Commission should disallow pending loads derived from studies to inform short-term investment plans. Finally, the Commission should limit

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24 *Id.*, Attachment A, Table 1, at 1, and 2-3; and Attachment C, Table 1, at 3, and 4-5.
25 *The Public Advocates Office's Informal Comments on the Pending Loads Workshop Report*, R.21-06-017 (May 1, 2025), at 2.
26 *Id.*, at 6.
27 *Ibid*.
28 *Id.*, at 7.

the use of pending loads derived from studies to the disaggregation of the IEPR forecast to inform medium- and long-term investment plans, so long as they do not exceed the IEPR forecast.

D. The Commission Should Require SDG&E to Incorporate Pending Loads into Its Proposed Scenario Planning Process and Prepare High and Low Scenarios Based on Confidence Level Categories

The Commission should require SDG&E to incorporate pending loads into its proposed scenario planning framework and prepare high and low scenarios based on the confidence levels associated with each pending loads category. SDG&E's proposed Pending Loads Framework, submitted in a separate advice letter,[29] did not provide a transparent, structured categorization of pending loads by confidence level or propose discount factors for low-confidence data types upon which alternative scenarios and investment plans can be based. Without confidence levels and alternative scenarios, the proposed Scenario Planning Framework lacks necessary guardrails for preventing overinvestment in grid upgrades.

SDG&E's proposed Scenario Planning Framework for the 2025-2026 DPP cycle includes only a Base Scenario and a Scenario 1. The Base Scenario compares the IEPR medium-duty and heavy-duty transportation electrification IEPR forecast with one SDG&E developed in-house. It takes the difference between the two as pending loads, assuming SDG&E's in-house estimates exceed the IEPR forecast.[30] It proposes a Scenario 1 based on a simulated power flow analysis that uses a 90 percent versus a 100 percent equipment rating to assess the potential need for grid upgrades.[31] Finally, SDG&E describes a potential Scenario 2 based on alternative IEPR scenarios, but does not propose it for the 2025-2026 DPP cycle.[32]

Unlike SDG&E, PG&E[33] and SCE[34] propose high, low, and base scenarios informed by their more robust pending loads frameworks. The base scenarios, which represent the most likely growth scenario and on which their investment plans are based, include high- and medium-confidence pending loads. The low scenarios inform short-term investments and are primarily based on high confidence pending loads. Finally, the high scenarios include all confidence-level pending loads and drive medium- and long-term investments. While there is room for improvement in PG&E's and SCE's proposed frameworks, they offer greater transparency and provide more protections against overinvestment in grid upgrades at ratepayer expense. The Commission should therefore require SDG&E to incorporate pending loads into its proposed

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29 *Joint Utilities' Pending Loads Implementation Advice Letter,* PG&E Advice 7630-E*,* SDG&E Advice 4676-E*, and* SCE Advice 5567-E) (June 27, 2025).
30 Advice Letter, at 5.
31 *Id*., at 6.
32 *Ibid*.
33 *Id*., Attachment A, Table 1, at 1.
34 *Id*., Attachment C, Table 1, at 3.

Scenario Planning Framework with high and low scenarios based on confidence levels, similar to PG&E's and SCE's proposals.

E. The Commission Should Reject PG&E's Proposals to Bypass Regulatory Approval for Modifying Its Scenario Planning Framework and for Identifying Planned Investments Incremental to the Base Scenario

The Commission should reject PG&E's proposals to bypass the regulatory approval process for adopting modifications to its scenario planning framework and for developing a method for identifying planned investments incremental to those included in the base scenario. PG&E asserts that it does not foresee the need to seek regulatory approval to modify its proposed scenario planning framework.[35] PG&E also asserts that the Energy Division approval, rather than Commission approval, would suffice to identify the process by which it could use scenario planning to identify investments incremental to those identified in the base scenario.[36]

These proposals create a risk for overinvestment in grid upgrades. Therefore, regulatory approvals, informed by stakeholder input, and a Commission determination on the process by which incremental investments beyond the base scenario could be made, are necessary. This is especially the case given scenario planning has never been tested previously, necessitating firm guardrails to protect ratepayers from bearing the costs of unused or underutilized grid investments.

PG&E offers the following justification for its request to exempt modifications to its proposed scenario planning framework from regulatory approval:

> PG&E does not anticipate any further regulatory approval to adjust the Framework. To avoid administrative burden, it is important that PG&E has the flexibility to make modifications to the scenarios if it is not altering the underlying approach. To the extent PG&E wished to modify the Scenarios but not alter the underlying purpose of the Scenarios, PG&E would inform the Commission and stakeholders of methodological or procedural changes via its annual reporting (i.e., GNA/DUPR and DFWG).[37]

PG&E further "proposes that the utilities may individually file a Tier 2 Advice Letter requesting modifications to the approved Scenario Planning Framework if they deem that fundamental changes to the Framework are required."[38]

While the Advice Letter process allows for stakeholder input and Commission review, PG&E does not define what it considers a fundamental change to the framework. Scenario

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35 *Id.*, Attachment A, at 3.
36 *Id.*, Attachment A, at 5.
37 *Id.*, Attachment A, at 3-4.
38 *Id.*, at 4.

planning has never been implemented in California, and when ratepayers are experiencing some of the highest rates in the nation, regulatory approval for changes to the proposed scenario planning framework is necessary. The Commission should, therefore, reject PG&E's request to bypass further regulatory approval and its proposal to develop a method for identifying planned investments incremental to those included in the base scenario.

F. The Commission Should Require the IOUs to Include CCAs in Their Data Reporting Proposals for Large Loads

The Commission should ensure that the CCAs can access customer usage and project data on large pending loads included in the IOUs' scenario plans. As the default generation service provider for customers within their service areas, CCAs are entitled to customer information pursuant to statute and rules established by the Commission, and CCAs must have information on large pending loads to plan to serve those loads. PG&E's scenario planning framework proposal discusses the confidentiality of customer data, but fails to include CCAs among the list of agencies entitled to this data:

> Note that the CPUC has established provisions regarding confidentiality of customer data, and customer data may therefore be classified as confidential information. However, confidential data can still be provided under declaration to stakeholders with access to such data (e.g., CPUC Energy Division staff, California Public Advocates Office), and the application of the 15/15 Rule will be clearly displayed in the Public GNA/DUPR filing.[39]

In D.12-08-045, the Commission made additional determinations concerning CCAs' access to and responsibility for customer information, making clear that such access and use is on par with that of the IOUs.[40] Therefore, CCAs should have access to all customer- and project-specific data, including the customer name, project location, forecasted in-service date, expected capacity, load type, pending load category, and information source. The Commission should affirm CCAs' existing rights to this data and require the IOUs to make this data available to CCAs without redaction, anonymization, or aggregation.

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[39] *Ibid.*

[40] D.12-08-045, *Decision Extending Privacy Protections to Customers of Gas Corporations and Community Choice Aggregators, and to Residential and Small Commercial Customers of Electric Service Providers*, R.08-12-009 (Aug. 31, 2012), at 4-5, and 23-26.

III. CONCLUSION

For the reasons described above, CalCCA respectfully requests the Commission:

- Require the IOUs to develop a demand flexibility scenario for the 2026–2027 DPP cycle that explores options for mitigating future grid upgrades;
- Require the IOUs to track and report on least-regrets investments for which the anticipated load did not materialize, and the disposition of any unused assets;
- Limit the ability of pending loads derived from studies to inform the IOUs' investment strategies;
- Require SDG&E to incorporate pending loads into its proposed scenario planning process and prepare high and low scenarios based on confidence level categories;
- Reject PG&E's proposal to bypass regulatory approval for modifying its scenario planning framework and for identifying planned investments incremental to the base scenario; and
- Require the IOUs to include CCAs in data reporting proposals for large loads.

CalCCA thanks the Energy Division for its review of this protest and for its consideration of the relief requested.

Respectfully submitted,

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

Leanne Bober

Leanne Bober,
Director of Regulatory Affairs and
Deputy General Counsel

cc via email:
PGETariffs@pge.com
GAnderson@sdge.com
SDGETariffs@sdge.com
AdviceTariffManager@sce.com
Karyn.Gansecki@sce.com
Service List: R.21-06-017

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

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

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION
APPLICATION FOR REHEARING OF DECISION 25-06-049**

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

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

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

On behalf of
CALIFORNIA COMMUNITY CHOICE
ASSOCIATION

July 28, 2025

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Specification of Legal Error

By applying a new methodology for calculating the RA MPB retroactively to the 2025 Final RA MPB, the Commission commits legal error in several respects.[1] The Commission:

- Fails to act within its power or jurisdiction, as required by section 1757(a)(1), by setting general rates and applying them retroactively in violation of section 728, and fails to proceed in the manner required by law, as required by section 1757(a)(2), by finding that the redesign of the RA MPB midstream in the 2025 ERRA process is not "general ratemaking," despite: (1) the consideration of many variables and formulating broad policy in the methodology change; and (2) the resulting significant impacts to LSEs and customers. The Decision's redesign of the PCIA accomplishes the same ends as other general ratemaking activities, such as those in GRCs, which set the methodology to calculate revenue requirements; and
- Failing to proceed in the manner required by law, as required by section 1757(a)(2), by not harmonizing the indifference statutes in sections 365.2, 366.1, 366.2, and 366.3 with section 728's prohibition on retroactive ratemaking. In fact, by applying the new methodology only prospectively, the Commission could accomplish this required harmonization; and
- Failing to support its decision with findings, as required by section 1757(a)(3), and failing to make findings supported by substantial evidence in light of the whole record, as required by section 1757(a)(4), based on an insufficient record to justify retroactive application of the RA MPB.

On these grounds, CalCCA respectfully requests that the Commission grant rehearing, permit oral argument, and issue an order that the Decision's new methodology for calculating the RA MPB does not apply to the Final 2025 RA MPB. Rather, the new methodology should only be applied on a prospective basis to the Forecast 2026 RA MPB and then in future ERRA proceedings.

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

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION
APPLICATION FOR REHEARING OF DECISION 25-06-049

Pursuant to California Public Utilities Code section 1731(b)(1)[2] and Rule 16.1 of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure,[3] California Community Choice Association (CalCCA)[4] submits this Application for Rehearing (AFR) of Decision (D.) 25-06-049 (Decision).[5] The Decision was voted out by the Commission on June 26, 2025, and issued on June 27, 2025.

I. INTRODUCTION

The Decision modifies the calculation methodology for the Resource Adequacy (RA) Market Price Benchmark (MPB), a critical component in the calculation of the Power Charge Indifference Adjustment (PCIA) revenue requirement (also known as the Indifference Amount). It applies the modification not only prospectively to the 2026 PCIA revenue requirement but also

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

3 *State of California Public Utilities Commission, Rules of Practice and Procedure, California Code of Regulations Title 20, Division 1, Chapter 1* (May 2021) (Commission Rules).

4 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.

5 D.25-06-049, *Decision Adopting Changes to the Calculation of the Resource Adequacy Market Price Benchmark,* R.25-02-005 (June 27, 2025).

retroactively to the 2025 PCIA revenue requirement that is already being recovered in rates. While a true-up from year to year is an established element of setting PCIA rates, ***changing the methodology*** between the calculation of the Forecast and the Final 2025 PCIA revenue requirements is not. By changing methodologies midstream, the Commission has engaged in unlawful retroactive ratemaking in violation of Public Utilities Code section 728.

The PCIA is a complex, Commission-established methodology that implements sections 365.2, 366.1, 366.2(f) and (h), and 366.3. The PCIA implements most of these statutory obligations by ensuring that investor-owned utilities (IOUs) recover procurement costs from the customers on whose behalf the IOU undertook the procurement. These customers include IOU bundled customers *or* unbundled customers of a community choice aggregator (CCA) or electric service provider (ESP) that have departed bundled service, to prevent cost shifting between bundled and unbundled customers. The PCIA implements section 366.2(g) by ensuring the conveyance – in kind or in value – of the departed customers' "fair and equitable share" of the portfolio benefits to offset costs.

The RA MPB is one of the mechanisms used to implement this requirement. It determines the value of capacity resources in the IOUs' portfolios that the IOUs retain to serve their bundled customers. The RA MPB methodology, utilized in the Commission's yearly Energy Resource Recovery Account (ERRA) proceedings to set PCIA rates, was established in Commission orders in 2018 and 2019 after lengthy PCIA rulemaking proceedings.[6] The Decision, issued in this successor PCIA proceeding after an expedited Track One conducted over the first five months of 2025, orders a complete redesign of the RA MPB, both changing its

6 *See* D.18-10-019, *Decision Modifying the Power Charge Indifference Adjustment Methodology*, R.17-06-026 (Oct. 11, 2018); *see also* D.19-10-001, *Decision Refining the Method to Develop and True Up Market Price Benchmarks*, R.17-06-026 (Oct. 10, 2019).

inputs and collapsing three benchmarks into one. The Decision applies the new RA MPB methodology retroactively to the 2025 PCIA revenue requirement and prospectively to the 2026 PCIA revenue requirement and beyond.[7]

The Commission errs by requiring the redesigned RA MPB to apply retroactively to the 2025 PCIA revenue requirement, in violation of section 728, and by misapplying California Supreme Court precedent in *Southern California Edison v. Public Utilities Commission*[8] (*Edison*). *Edison* found that section 728 prohibits the Commission from retroactive ratemaking when setting "general rates."[9] The Decision states that *Edison* "emphasized that [prior decisions] interpreting section 728 as a prohibition against retroactive ratemaking [were] not intended to apply to every situation where action by the Commission results in retroactive application."[10] It concludes, summarily and without any analysis of relevant statutes or PCIA ratemaking procedures, that "this [Order Instituting Rulemaking (OIR)] proceeding, and this decision, ***do not set general rates***."[11]

To the contrary, PCIA ratemaking tracks closely with other general ratemaking practices such as those conducted in General Rate Cases (GRCs). In addition, the Commission's actions meet the requirements of *Edison* to qualify as general ratemaking given: (1) the Commission has conducted complex weighing of competing policies and values; and (2) the Decision has a substantial financial impact on load-serving entities (LSE). Applying the redesigned RA MPB

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[7] Decision, Conclusion of Law (COL) 10 ("The changes should be applied to the calculation of the 2025 Final and 2026 Forecast RA MPB").

[8] *Southern California Edison v. Public Utilities Commission* (1978) 20 Cal.3d 814, 816.

[9] *Ibid.*

[10] Decision, at 26.

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

methodology retroactively to the 2025 revenue requirement is therefore unlawful under section 728 and *Edison.*

By applying the new methodology for calculating the RA MPB retroactively, the Commission commits legal error in several respects. The Commission:

- Fails to act within its power or jurisdiction, as required by section 1757(a)(1), by setting general rates and applying them retroactively in violation of section 728, and fails to proceed in the manner required by law, as required by section 1757(a)(2), by finding that the redesign of the RA MPB midstream in the 2025 ERRA process is not "general ratemaking," despite: (1) the consideration of many variables and formulating broad policy in the methodology change; and (2) the resulting significant impacts to LSEs and customers. The Decision's redesign of the PCIA accomplishes the same ends as other general ratemaking activities, such as those in GRCs, which set the methodology to calculate revenue requirements; and
- Failing to proceed in the manner required by law, as required by section 1757(a)(2), by not harmonizing the indifference statutes in sections 365.2, 366.1, 366.2, and 366.3 with section 728's prohibition on retroactive ratemaking. In fact, by applying the new methodology only prospectively, the Commission could accomplish this required harmonization; and
- Failing to support its decision with findings, as required by section 1757(a)(3), and failing to make findings supported by substantial evidence in light of the whole record, as required by section 1757(a)(4), based on an insufficient record to justify retroactive application of the RA MPB.

On these grounds, CalCCA respectfully requests the Commission grant rehearing, permit oral argument, and issue an order that the Decision's new methodology for calculating the RA MPB does not apply to the 2025 revenue requirement. Rather, the new methodology should only be applied on a prospective basis to the Forecast 2026 RA MPB and then in future ERRA proceedings.

II. BACKGROUND AND PROCEDURAL HISTORY

A. The Commission's PCIA Methodology Implements the Indifference Requirements of Sections 365.2, 366.1, 366.2, and 366.3

Sections 365.2, 366.1, 366.2, and 366.3 require the Commission to ensure indifference and prevent cost shifts between bundled customers and unbundled customers. To achieve these objectives with respect to a customer departing IOU service for a CCA, sections 366.2(d) and (f) permit the IOUs to recover any net unavoidable electricity costs incurred while the CCA customer was served as an IOU bundled customer. Section 366.2(g), however, requires the Commission to reduce the amount of estimated "net unavoidable [IOU] electricity costs" paid by CCA customers "by the ***value*** of any benefits that remain with bundled service customers, unless the customers of the [CCA] are ***allocated a fair and equitable share of those benefits***."[12] The Commission adopted the PCIA methodology to meet these statutory requirements.

B. The PCIA Methodology, Established in the PCIA Ratesetting Proceeding, Sets the Revenue Requirement, or Indifference Amount, for the PCIA Rate for a Given Year in the IOUs' ERRA Forecast Proceedings

The PCIA calculation methodology is set in a PCIA ratesetting proceeding applicable to all three IOUs. As noted in the prior PCIA proceeding, Rulemaking (R.) 17-06-026, and this current PCIA proceeding, the proceeding to set the PCIA methodology is categorized as "ratesetting."[13] Rule 1.3(g) of the Commission's Rules of Practice and Procedure defines "ratesetting" proceedings as:

> [P]roceedings in which the Commission sets or investigates rates for a specifically named utility (or utilities), or ***establishes a***

[12] Section 366.2(g) (emphasis added).

[13] *See Scoping Memo and Ruling of Assigned Commissioner,* R.17-06-026 (Sept. 25, 2017), at 25 ("the category of this proceeding is determined to be ratesetting); *Phase 2 Scoping Memo and Ruling of Assigned Commissioner,* R.17-06-026 (Feb. 1, 2019), at 15 ("the category of Phase 2 of this proceeding is . . . determined to be ratesetting") ; *Assigned Commissioner's Scoping Memo and Ruling,* R.17-06-026 (Dec. 16, 2020), at 7 ("The initial Scoping Ruling determined the category of Phase 1 of this proceeding to be ratesetting. The category of Phase 2 of this proceeding is also determined to be ratesetting. The determination made in the previous scoping memo is maintained."); *Assigned Commissioner's Second Amended Scoping Memo and Ruling,* R.17-06-026 (June 24, 2022), at 5 ("The 2019 Scoping Memo and 2020 Scoping Memo determined that the category of Phase 2 of this proceeding is ratesetting. This second amended Scoping Memo maintains this categorization of Phase 2."); *Assigned Commissioner's Scoping Memo and Ruling,* R.25-02-005 (Apr. 8, 2025), at 4 ("This ruling confirms the Commission's preliminary determination [in the OIR] that this is a ratesetting proceeding.").

> ***mechanism that in turn sets the rates*** for a specifically named utility (or utilities).[14]

In both R.17-06-026 and this successor PCIA ratesetting proceeding, the Commission is doing just that – establishing the mechanism that in turn will result in rates after application of the methodology in each IOU's ERRA Forecast case. Despite this clear delineation of the PCIA proceeding as ratesetting, however, the Decision finds that "[t]his OIR proceeding, and this decision, do not set general rates."[15]

After the PCIA mechanism is established in the PCIA proceeding, the PCIA for each IOU is then established in each IOU's ERRA Forecast case, subtracting from PCIA-eligible utility generation costs (portfolio costs) the value of the PCIA generation portfolio (portfolio value). The result is the Indifference Amount (also known as the PCIA revenue requirement), as demonstrated in Figure 1.

<u>FIGURE 1</u>

While costs can be readily forecasted and finally determined by actual recorded data, determining portfolio value is subjective. The existing PCIA methodology determines the ***forecast portfolio value*** by applying a forecast price for energy, RA, and renewables portfolio standard (RPS) resources to a forecast quantity of each product, as demonstrated below in Figure 2. The methodology derives those prices using market value proxies – referred to as Market Price Benchmarks, and each MPB is developed using a separate methodology. The forecast energy

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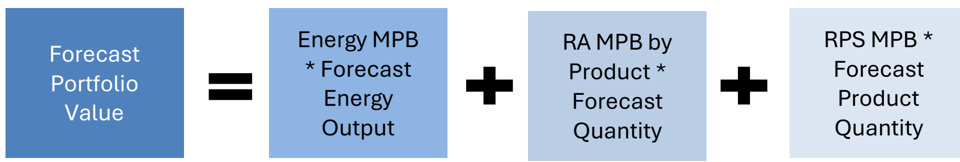
14 Commission Rule 1.3(g) (emphasis added).
15 Decision, at 27.

price looks to published energy index prices; the forecast RA and RPS MPBs are proxy market values[16] developed by the Commission administratively based on a particular methodology using market survey data collected by the Energy Division.

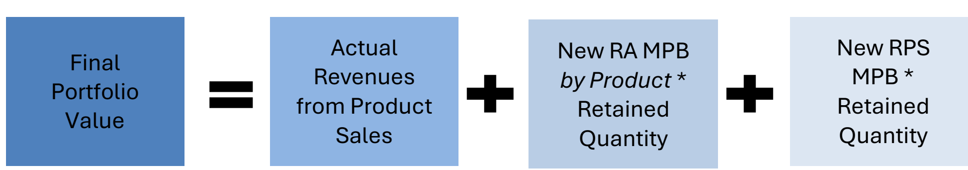
FIGURE 2



The PCIA revenue requirement built from these forecasted valuations is recovered through rates from bundled and unbundled customers during the forecast year (here, 2025).

A year later during each IOU's subsequent ERRA Forecast case, the Commission modifies the earlier-determined revenue requirement. That modification is made to reflect, among other things, actual revenues received for products sold from the portfolio and to reflect a zero-dollar value for products left unsold from the portfolio. The revenue requirement modification also updates the proxy market values for products the utilities used to serve bundled customers, changing the *forecast* energy, RPS and RA MPBs to *final* energy, RPS and RA MPBs. This "true-up" relies on the same methodology used for the forecast and determines the final portfolio value, as shown in Figure 3.

FIGURE 3



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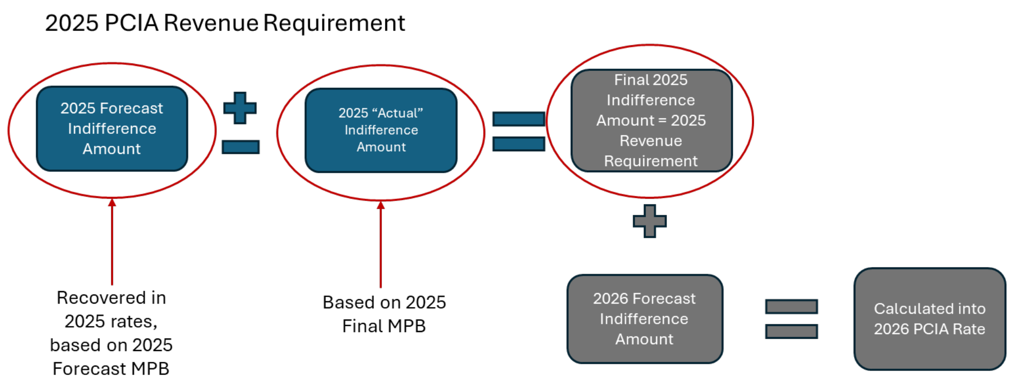
[16] *See* D.18-10-019; *see also* D.19-10-001, at 6 ("Market Value is the estimated financial value, measured in dollars, that is attributed to a utility portfolio of energy resources for the purpose of calculating the [PCIA] for a given year.").

The utilities will calculate this final 2025 final portfolio value, use it as an input to the actual 2025 indifference amount, and finalize the 2025 revenue requirement in the 2026 ERRA Forecast proceedings, as shown below in Figure 4.

FIGURE 4



Changing any part of that methodology, including the methodology to calculate the RA MPB, will change the revenue requirements and the allocation of PCIA-eligible costs—and the Commission's definition of customer indifference—for a given year. This is because the market cost of resources retained to serve bundled customers is recovered only from bundled customers via the ERRA rate. All costs that rise above the market value of the IOUs' portfolio are recovered from both departed and bundled customers via the PCIA rate,[17] which appears as a separate line item on unbundled customer bills.[18] The result is a zero-sum game between bundled and unbundled customers. If the portfolio market value increases, all other things equal, the Indifference Amount decreases. If the Indifference Amount decreases, the PCIA decreases, and

[17] The total generation costs for a bundled customer are its ERRA rates plus the PCIA rate. The total generation costs for a departed customer are the PCIA plus the cost of procurement of their CCA or ESP.

[18] D.20-03-019, *Decision Considering Working Group Proposals on Departing Load Forecast and Presentation of Power Charge Indifference Adjustment Rate on Bills and Tariffs,* R.17-06-026 (Apr. 6, 2020), at 21.

departed customers pay less. If the Indifference Amount increases, the PCIA increases, and departed customers pay more.

Thus, any change to the RA MPB methodology that decreases its value will result in departed customers paying more and bundled customers paying less, and vice versa. As set forth below, such a profound change to the ratemaking methodology can only be done on a prospective basis to avoid unlawful retroactive ratemaking.

C. The Decision Changed the Methodology for Calculating the RA MPB Midstream During the Calculation and Recovery of the 2025 ERRA Revenue Requirement in Rates

The Decision modified the methodology for determining the RA MPB *between* establishing the 2025 forecast revenue requirement and establishing the 2025 final revenue requirement. Prior to the Decision, including for the PCIA rates set in the 2025 ERRA Forecast cases, the Forecast RA MPB was separated by RA product type and an average price was derived using the following subset and timeframe of confidential market survey data collected by Energy Division:

- <u>For system and flexible RA</u>: transactions executed for delivery in 2025 based on confidential data collected by Energy Division from September of the year two years prior (2023), and through August of the prior year (2024).
- <u>For local RA</u>: transactions executed for delivery in 2025 from the full second (2023) and third years prior (2022), and through August of the prior year (2024).

Prior to the Decision, the Final RA MPB was calculated based on data from a later time period, but otherwise *based on the same methodology*:

- <u>For system and flexible RA</u>: the full prior year (2024), and through August of the current year (2025).
- <u>For local RA</u>: the full three prior years (2022-2024), and through August of the current year (2025).

The Decision redesigns this methodology based primarily on an Energy Division Staff Report identifying "issues inherent to the methodology that may be undermining customer cost indifference."[19] First, the Decision combines the transactions for all three RA products to produce a single RA benchmark rather than three distinct benchmarks.[20] Second, it extends the measurement periods for data used to determine the 2025 Final RA MPB, adopting a three-year transaction window for the annual Forecast RA MPB and a four-year transaction window for the Final RA MPB.[21]

Both changes modify how the Commission defines customer indifference. The 2025 Forecast PCIA revenue requirement was established under the former methodology, while the 2025 Final PCIA revenue requirement is being established under the redesigned methodology – after the IOUs had already started recovering the 2025 revenue requirement in rates. The Decision has therefore rewritten how to determine the value of the utility's portfolio in 2025, and, in turn, revised the Commission's definition of indifference for 2025 in an unlawful, retroactive manner.

III. STANDARD OF REVIEW

Per Rule 16.1(c) and section 1732, AFRs must set forth specifically the grounds on which a decision in question is "unlawful or erroneous." The purpose of an AFR is "to alert the Commission to a legal error, so that [it] may correct it expeditiously"[22] and to "provide[] the Commission with sufficient notice to respond to [the] claims."[23] CalCCA therefore refers the Commission to the following specific portions of the Decision that are unlawful and erroneous:

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19 *See Energy Division Staff Report of the 2024-2025 Resource Adequacy Market Price Benchmark,* attached to *Chief Administrative Law Judge's Ruling Adding Energy Division Report to the Record and Setting the Schedule for Comments on the Report,* R.25-02-005 (Feb. 26, 2025) (Staff Report).

20 Decision, at 19, COL 2, at 30, and Ordering Paragraph (O¶) 1, at 31.

21 *Id.* at 20, COL 2, at 30, and O¶ 1, at 31. The Decision also develops a method for excluding swap, affiliate, and one half of sleeve transactions. *Id.* at 30, O¶ 5, 8.

22 Commission Rule 16.1(c).

23 *Util. Consumers' Action Network v. Pub. Util. Comm.* (2010) 187 Cal.App.4th 688, 705.

Location in Decision	Unlawful or Erroneous Statement
Section 6	"This OIR proceeding, and this decision, do not set general rates."[24]
Section 6	"The changes adopted herein work to improve the dataset and the RA MPB calculations."[25]
Section 6	"Nothing in the statutes mandating indifference limits our authority to modify the indifference calculation methodology when necessary. We find that it would be inconsistent with the statutory mandate to ensure indifference to make the above findings yet prohibit the adopted remedy from being applied immediately. Accordingly, the Energy Division is directed to apply the new methodology in the calculation of the 2025 Final RA MPB and in succeeding forecast and final MPBs."[26]
Section 1.3	"The testimony at issue here is relevant and somewhat probative of the issues in scope for Track One of the OIR. However, it is cumulative of the record evidence, the Energy Division Staff Report."[27]
Section 1.3	"[N]o party substantially disputes the factual record before us in the Staff Report[.]"[28]
Section 1.3	"[W]e find the factual record established by the Staff Report to be sufficient to support both our factual and policy determinations."[29]
Section 1.3	"[W]e conclude that the probative value of the proffered testimony is substantially outweighed by the probability that its inclusion will necessitate an undue consumption of time."[30]
COL 9	"Application of these changes to the 2025 Final RA MPB does not violate the prohibition against retroactive ratemaking.[31]
COL 10	"The changes adopted should be applied to the calculation of the 2025 Final and 2026 Forecast RA MPB and all succeeding forecast and final MPB calculations."[32]
O¶ 2	"The methodology adopted in this decision shall be effective immediately."[33]

24 Decision, at 27.
25 *Ibid*.
26 *Ibid*.
27 *Id*. at 10.
28 *Id*. at 10-11.
29 *Id*. at 11.
30 *Ibid*.
31 *Id*. at 34.
32 *Ibid*.
33 *Id*. at 35.

Commission decisions in ratemaking proceedings such as the instant case are reviewed pursuant to section 1757.[34] As set forth below, CalCCA respectfully requests rehearing of the Decision's retroactive application of the redesigned RA MPB, based on the fact that the Commission: (1) acted without, or in excess of, its powers or jurisdiction;[35] (2) has not proceeded in the manner required by law;[36] (3) has not supported its decision by the findings;[37]

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34 Section 1757(a).

35 Section 1757(a)(1). The interpretation of statutes that define or circumscribe the Commission's jurisdiction is a question of law subject to independent judicial review. *PG&E Corp. v. Pub. Util. Comm'n* (2004) 118 Cal.App.4th 1174, 1194–1195 (citing *Yamaha Corp. of America v. State Bd. of Equalization* (1998) 19 Cal.4th 1, 7). While an agency's interpretation of certain statutes is afforded presumptive value given the agency's "special familiarity and presumed expertise with satellite legal and regulatory issues," such deference does not apply when the issue is the scope of the agency's jurisdiction. *PG&E Corp. v. Pub. Util. Comm'n* (2004) 118 Cal.App.4th 1174, 1194 (citing *Kaiser Foundation Health Plan, Inc. v. Zingale* (2002) 99 Cal.App.4th 1018).

36 Section 1757(a)(2). The Commission fails to "proceed[] in the manner required by law" when it violates its own procedural rules, its own decisions, or applicable statutes. *Calaveras Telephone Co. v. Pub. Util. Comm'n* (2019) 39 Cal.App.5th 972, 983; *see also Southern California Edison Co. v. Pub. Util. Comm'n* (2006) 140 Cal.App.4th 1085, 1104-1106 (interpreting the parallel language in section 1757.1(a)(2): "The commission has not proceeded in the manner required by law"). For example, a failure to proceed in the manner required by law can occur when the Commission fails to correctly apply a legal standard, or relies on an "unreasonable interpretation" of a statute. *See City of Marina v. Board of Trustees of Cal. State Univ.* (2006) 39 Cal.4th 341, 355; *The Utility Reform Network v. Pub. Util. Comm'n* (2014) 223 Cal.App.4th 945, 958.

37 Section 1757(a)(3). "[F]indings afford a rational basis for judicial review. . . . The more general the findings, the more difficult it is for the reviewing court to ascertain the principles relied upon by the administrative agency. Even when the scope of review is limited, as in this case (Pub. Util. Code, § 1757), findings on material issues enable the reviewing court to determine whether the commission has acted arbitrarily." *Cal. Motor Transport Co. v. Pub. Util. Comm'n* (1963) 59 Cal.2d 270, 274 (citation omitted).

and (4) fails to support the findings in the decision by substantial evidence in light of the whole record."[38] Each of the Commission's errors are described in detail below.[39]

IV. THE COMMISSION FAILED TO ACT WITHIN ITS JURISDICTION AND FAILED TO PROCEED IN THE MANNER REQUIRED BY LAW BY ENGAGING IN UNLAWFUL RETROACTIVE RATEMAKING IN VIOLATION OF SECTION 728

The Commission failed to act within its jurisdiction, and failed to proceed in the manner required by law, by engaging in "general ratemaking" by redesigning the calculation methodology for the RA MPB and applying it retroactively to the 2025 PCIA revenue requirement in violation of section 728. Section 728 grants the Commission the authority to "fix, by order," the "just, reasonable, or sufficient rate, classifications, rules, practices, or contracts to be ***thereafter*** observed and in force."[40] The California Supreme Court has held that section 728

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[38] Section 1757(a)(4). A "substantial evidence" analysis considers whether the Commission relies on "such relevant evidence as a reasonable mind would accept as adequate to support a conclusion," and whether "it is evidence which is reasonable in nature, credible, and of solid value." *Los Angeles County Dept. of Children & Family Servs. v. Sup. Ct.* (2013) 222 Cal.App.4th 149. While "it is for the agency to weigh the preponderance of conflicting evidence, consideration of the whole record means the court will not simply 'isolate only the evidence which supports the [Commission's] findings and thus disregarded relevant evidence' that tends to undermine them." *Ponderosa Tel. Co. v. Pub. Util. Comm'n* (2019) 36 Cal.App.5th 999, 1013; *see also Bixby v. Pierno* (1971) 4 Cal.3d 130, 149 n.22. The courts "must consider all relevant evidence in the administrative record including evidence that fairly detracts from the evidence supporting the agency's decision. *County of San Diego v. Assessment Appeals Bd. No. 2* (1983) 148 Cal.App.3d 548, 554. When making that inquiry, the "court must ensure that an agency has adequately considered all relevant factors, and has demonstrated a rational connection between those factors, the choice made, and the purposes of the enabling statute. "*Cal. Community. Choice Assoc. v. Pub. Util. Comm'n.* (2024) 103 Cal.App.5th 845, 861 (citing *Securus Technologies, LLC v. Pub. Util. Comm.* (2023) 88 Cal.App.5th 787, 802-803).

[39] Section 1757 also allows review if the Decision "was procured by fraud or was an abuse of discretion," or if it "violates any right of the petitioner under the [United States or California] Constitution[s]." Pub. Util. Code § 1757(a)(5), (6). In addition, CalCCA maintains that section 1757 provides the relevant standard for this ratemaking. However, should the Commission believe that section 1757.1 provides the appropriate standard (applying to proceedings that are not ratemakings), the majority of CalCCA's ensuing analysis still applies. Sections 1757.1(a)(3), 1757.1(a)(2), and 1757.1(a)(4) provide the same standard as 1757(a)(1), 1757(a)(2), and 1757(a)(3) (respectively). Section 1757.1 has no analogue for section 1757(a)(4), however, so the argument relating to the Commission's findings not being supported by substantial evidence when viewed in light of the whole record would not apply.

[40] Section 728 (emphasis added).

limits the Commission's jurisdiction by prohibiting ratemaking being applied retroactively.[41] In *Edison,* the Court observed that "before there can be retroactive ratemaking there must at least be ***ratemaking,"*** and proceeded to define the hallmarks of "general ratemaking" to be that: (a) the Commission considered "many variables" and formulated "broad policy" in its setting of the "general rates"; and (b) the Commission's action had a significant financial impact on customers and LSEs affected that would not have otherwise occurred.[42]

The Decision provides no analysis of whether redesigning the RA MPB amounted to "general ratemaking." Rather, the Commission simply ***finds*** that "[t]his OIR proceeding, and this decision, do not set general rates."[43] The Commission states:

> In its briefs and comments, CalCCA argues that the changes adopted herein should not take effect until the 2026 Forecast. It argues that applying this methodology to the Final 2025 calculations would violate principles prohibiting retroactive ratemaking. Curiously, CalCCA grounds this argument in the 1978 California Supreme Court decision in *Southern California Edison v. Public Utilities Commission* (20 Cal.3d 813). In *Edison,* the Supreme Court upheld our decision requiring SCE to return surcharge fees to customers after we found flaws in the methodology previously approved for collecting the fees. The *Edison* decision emphasized that the court's 1965 decision [citing *Pacific Telephone*] interpreting Section 728 as a prohibition against retroactive ratemaking was not intended to apply to every situation where action by the Commission results in retroactive application. The principle only applies to setting general rates. [citing *Edison*]. This OIR proceeding, and this decision, do not set general rates.[44]

The Commission also states in COL 9 that "[a]pplication of these changes to the 2025 Final RA MPB does not violate the prohibition against retroactive ratemaking."[45] Instead, the Commission

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41 *Pacific Tel. & Tel. Co. v. Pub. Utils. Comm'n* (1965) 62 Cal.2d 634, 650-652; *Edison*, 20 Cal.3d at 817-818 (reaffirming *Pacific Telephone's* conclusion that "***general rate making*** is legislative in character and looks to the future") (emphasis added).

42 *Edison*, 20 Cal.3d at 828-830.

43 Decision, at 27.

44 *Id.* at 26-27.

45 *Id.* at COL 9, at 31.

justifies its decision by stating that its statutory mandate to ensure indifference requires it to apply the refined methodology "immediately" in the "calculation of the 2025 Final RA MPB and in succeeding forecast and final MPBs."[46] Finally, the Commission states that "[t]he 2025 forecast was not a guarantee of the final 2025 outcome and was always subject to the indifference mandate."[47]

The Commission errs in concluding that refining the RA MPB was not general ratemaking. First, this PCIA proceeding, as well as its predecessor proceeding, R.17-06-026, have always been categorized as "ratesetting" proceedings.[48] This makes sense given the Commission's definition in its Rule 1.3(g) of a ratesetting proceeding as "establish[ing] a mechanism that in turn sets the rates for a specifically named utility [or utilities]."[49] The PCIA proceedings, which establish the components of the PCIA calculation methodology, therefore fit exactly into the Commission's definition of ratesetting.

Second, if the Commission had conducted the analysis required by *Edison,* it would have found general ratemaking took place given: (1) the process to refine the RA MPB required many variables to be taken into account to formulate broad ratemaking policy; and (2) the impact of the decision is significant for LSEs and customers. In addition, finding that PCIA rate design through the modification to the RA MPB is not "general ratemaking," similar to ratemaking in GRCs, leads to an absurd conclusion that the PCIA is never "general ratemaking." To the contrary, the "general rate" applied to the 2025 revenue requirement amounts to unlawful retroactive ratemaking.

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46 *Id.* at 27.
47 *Ibid.*
48 *See supra,* n. 14.
49 Commission Rule 1.3(g).

A. The Commission Engaged in General Ratemaking

1. *Edison* Outlines the Hallmarks of General Rates to Be the Consideration of a Complex Balancing of Many Values with a Significant Impact

The Decision's perfunctory conclusion that "[t]his OIR proceeding, and this decision, do not set general rates" fails when considering the analysis required by *Edison.* When *Edison* was decided in 1978, the Commission almost exclusively conducted ratesetting in GRCs,[50] so the question of whether general rates were set was closely tied to whether they were set after the opportunity for a hearing in a GRC. But that is not the case anymore. The Commission has now spliced general ratesetting across tens of open ratemaking proceedings that modify revenue requirements, cost allocation and/or rate design, including the PCIA. Therefore, identifying whether rates are general or non-general requires the Commission to follow the substantive analysis the Court used in *Edison*.

Edison concerns the Commission's power to change a fuel cost adjustment mechanism retroactively.[51] When determining whether general ratemaking occurred, the Court analyzed whether: (a) the Commission's process considered "many variables" and formulated "broad policy," and is not simply an exercise in basis arithmetic to reflect verifiable costs; and (b) the Commission's action had a significant impact on customers and LSEs affected that would not have otherwise occurred.[52] *Edison* also explains that section 728's limits on the Commission's jurisdiction applies to attempts to change a rate that was set after the parties had an opportunity

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

51 *Edison*, 20 Cal.3d at 815.

52 *Id.* at 828-830.

to present disputed facts to the Commission at a hearing.[53] If those indicia are present, general ratemaking has occurred and section 728 forbids retroactive application. *Edison* contrasts this with the non-general rates at issue in that case—those relating to an advice letter-based fuel cost adjustment mechanism. Those changes were to non-general rates because they did not require a hearing-assisted, complex policy analysis but were a "matter of simple arithmetic"[54] applied to "narrowly restricted and semi-automatic functioning" rates.[55] They were the result of depositing actual, real, verifiable facts into a simple arithmetic formula.

Edison does not forbid the Commission from ever looking backwards to identify unjust rewards and require parties to disgorge them through future rate adjustments. *Edison* does not preclude the Commission from developing and using balancing and memorandum accounts to handle the application of "a mathematical formula to a figure definitively established by reference to the utilities' books,"[56] as the Commission often does. But *Edison* does clarify that the Commission may ***only*** conduct such exercises when setting non-general rates.

Neither California courts nor the Commission have significantly expanded upon the narrow exception to retroactive ratemaking established in *Edison*.[57] However, in *Ponderosa*

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53 *Id.* at 829-830. The fact that parties in ratesetting proceedings often work to narrow their disputes and generate a record using modern discovery techniques—and that they therefore waive hearings regularly to present their arguments in filings and save the Commission and parties resources and time—cannot and should not be enough to add jurisdiction to the Commission to apply rates retroactively. *See City of Los Angeles v. Pub. Utils. Comm'n* (1975) 15 Cal.3d 680, 697 (noting that the purpose of the hearing in section 728 is simply "to air the policy considerations behind various rate proposals and to establish controverted facts").

54 *Edison*, 20 Cal.3d at 818.

55 *Id.* at 828.

56 *City of Los Angeles*, 15 Cal.3d at 697.

57 *But see Towards Utility Rate Normalization v. Pub. Util. Comm'n* (1988) 44 Cal.3d 870 (determining a major-additions adjustment clause account is not retroactive ratemaking); *Cal. Mfrs. Assn. v. Pub. Util. Comm'n* (1979) 24 Cal.3d 251 (determining a rate allocation methodology within an "offset proceeding" is not retroactive ratemaking); *see also* D.92317, 1980 Cal. PUC LEXIS 844, *3 (Oct. 8, 1980) (characterizing *Edison* as a limited exception to the rule against retroactive ratemaking, and reiterating that the rule is broad in its application). The Commission has continued to evaluate the same

Telephone Company v. Public Utilities Commission, the California Court of Appeals found prohibited retroactive ratemaking had occurred when the Commission retroactively revised a ratesetting formula – a change in methodology – for gains on sale of stock from a telephone company.[58] The rate formula had been set via a rulemaking requiring 66 percent of the proceeds from the sale to be conveyed to ratepayers and 33 percent to shareholders.[59] In an eleven-utility consolidated application seeking to disburse funds from a gain on sale in line with that formula, the Commission revised the formula to convey 100 percent of the proceeds to ratepayers.[60] The court determined the Commission's revision of the formula – set in a rulemaking categorized as ratesetting – "retroactively revises costs that formed the basis for prior general rates," concluding that "[t]his is precisely the type of action prohibited by the retroactive ratemaking doctrine."[61]

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factors the Court looked to in *Edison*. A line of Commission cases applies the *Edison* exception, finding that the retroactive nature of different balancing accounts, memo accounts, fuel clauses, and other similar mechanisms do not, on their own, constitute general ratemaking, especially when such mechanisms have little effect on rates. *See* D.92317 at *3-5; D.09-06-053, *Order Instituting Investigation to Consider Policies to Achieve the Commission's Conservation Objectives for Class A Water Utilities and Denying Rehearing of Decision in All Other Respects*, I.07-01-022, *et al.* (June 18, 2009), at 9 (recognizing that the Commission OII at issue was not a general ratemaking proceeding, and a memorandum account to track and potentially recover a specific, very limited class of costs is not general ratemaking); D.01-03-082, *Interim Opinion Regarding Proposed Rate Increases*, A.00-11-038, *et al.* (Mar. 27, 2001), at 50 (rejecting arguments that a true-up constituted retroactive ratemaking, recognizing that the true-up served to carry-out legislative intent and did not change any rates); D.04-03-041, 2004 Cal. PUC LEXIS 80, at *14-15 (Mar. 17, 2004) (revised balancing account procedures in question did not adjust general rates set by the Commission based on hindsight review of a utility's earnings, was not part of a general ratemaking proceeding, and had no effect on general rates); 1982 Cal. PUC LEXIS 1270, at *12 (Apr. 28, 1982) (concluding that inclusion of past franchise fees in the utility's proposed rate adjustment did not constitute retroactive ratemaking because over time, inclusion of the past fees would produce the same result as the normal course of business for the utility); D.12-03-026, 2012 Cal. PUC LEXIS 135, at *29-30 (Mar. 8, 2012) (recognizing that evaluating applicability of the rule against retroactive ratemaking requires determination of the origin of the rates underlying refunds being challenged).

[58] *Ponderosa Tel. Co. v. Pub. Utils. Comm'n* (2011) 197 Cal.App.4th 48, at 63-64.

[59] *Id.* at 54 (citing to D.06-05-041, *Opinion Regarding Allocation of Gains on Sale of Utility Assets*, R.04-09-003 (May 30, 2006) (as modified by D.06-12-043, *Order Modifying Decision (D). 06-05-041 and Denying Rehearing of Decision, as Modified*, R.04-09-003 (Dec. 14, 2006)).

[60] *Id.* at 54, 64.

[61] *Id.* at 64-65.

Similarly, the Commission's finding that it did not set general rates here is in error in that in redesigning the RA MPB the Commission did the following: (1) it set a ***new methodology*** to calculate an ***administratively set*** benchmark adopted via a ***ratesetting proceeding*** that weighed ***substantial questions of policy***; and (2) the new methodology will have **a *significant impact on rates*** that ***would not have otherwise occurred***.

2. The Commission Weighed Several Complex Factors and Concepts in Modifying the RA MPB, Meeting the First *Edison* Requirement

The Decision demonstrates why setting the methodology for calculating the RA MPB portion of the PCIA is setting a general rate under *Edison*. *Edison* found that general ratemaking takes place when a rate mechanism is being revised or adopted and there is "a plenary consideration" of the advantages and disadvantages of the proposed revisions.[62] If the variables in the ratemaking formula are just being updated to reflect something like recent prices, a full ratesetting hearing is unnecessary and would be tantamount to "a yearly charade attendant to its application."[63] The OIR describes the PCIA as "a ratemaking element that enacts and ensures indifference to all customers, bundled and unbundled," and "the mechanism developed to facilitate cost equity between third-party providers and the incumbent utility."[64] Fashioning this rate does not amount to the application of "a mathematical formula definitively established by reference to the utilities' books," or of a "matter of simple arithmetic"[65] applied to "narrowly restricted and semi-automatic functioning" rates.[66] It is a reformulation of how to value an IOU's capacity portfolio and, in turn, a rewriting of the Commission's definition of customer indifference.

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62 *Edison,* 20 Cal.3d at 829.
63 *Ibid.*
64 OIR, at 12.
65 *Edison,* 20 Cal.3d at 818.
66 *Id.* at 828.

In Track One, the Commission weighed five different Staff Proposals to change the current methodology of calculating the RA MPB to address increasing transaction volumes aimed at how to best reflect the value of capacity held in the IOUs' generation portfolios.[67] The OIR recognized the many complex variables the Commission must consider to set that policy, including "[s]hifts in today's energy market costs relative to the contract prices of older resources," how those shifts "can drive changes in the PCIA" and, as a result, "the relative cost share between bundled and departed customers."[68] The also OIR noted how "[t]he RA market has experienced extreme increases in the price for system RA, specifically during peak summer months," and how those increases have "led to rapid increases in the RA market price benchmarks in the past few years, which has increased the market value of IOU portfolios compared to the costs of those portfolios, resulting in PCIA shifting from serving as a charge to a credit on the bill of some departed load customers."[69]

Throughout the proceeding, CalCCA asserted that the Commission's process was too abbreviated and narrow and did not permit a full exploration of all the issues that the Commission ruled in scope for this phase of the rulemaking.[70] Yet even assuming the Commission considers all the necessary factors, the Decision itself demonstrates that developing the new PCIA formula still requires:

- Setting the appropriate historical window to include when calculating the MPB;[71]

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67 OIR, at 19-23.
68 *Id.* at 14.
69 *Ibid.*
70 *See* CalCCA OIR Opening Comments (Mar. 18, 2025) at 25; CalCCA OIR Reply Comments (Apr. 2, 2025), at 14-15; CalCCA Opening Brief (Apr. 21, 2025), at 17-22; CalCCA Reply Brief (Apr. 30, 2025), at 8-11; CalCCA PD Opening Comments (June 12, 2025), at 4-5; CalCCA PD Reply Comments (June 17, 2025), at 2-4.
71 Decision, at 20.

- Deciding whether, and how large, a change in the number of RA transactions occurring triggered the need to develop a new methodology;[72]
- Deciding whether to consider policy changes that might explain temporary changes in transaction volumes or prices;[73]
- Deciding whether to set the limits on what transactions to include in the calculation based on the absolute numbers of transactions, or the percentage of the volume of RA transacted in the period;[74]
- What categories, if any, should be combined, collapsed, or broken out to classify RA transactions when deriving MBPs;[75] and
- What constitutes a "market-based transaction" and whether certain transactions do not have sufficient indicia to qualify for the calculation.[76]

Indeed, the Decision itself summarizes that "questions that predominate this track of the OIR are of ***policy***."[77]

Clearly these issues are distinguishable from automatic fuel clause adjustments considered in *Edison.* As in *Ponderosa*, the Commission here is weighing whether and how to ***revise*** an existing ratemaking formula, specifically the formula set forth in D.19-10-001 requiring ED to true up the RA MPB based on the "volume-weighted average of all IOU, CCA and ESP RA-only market transactions" in the past 12 months.[78] There can be no question the Commission is conducting a plenary discussion of the policy underlying the PCIA.

Indeed, the Commission has previously explained that addressing "general policy issues regarding PCIA ratemaking methodology," is out of scope in a GRC and is "more appropriately considered in a Commission rulemaking."[79] Both the Commission's conclusions and its prior

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72 *Id*. at 16.
73 *Id*. at 25.
74 *Id*. at 14.
75 *Id.* at 12-20.
76 *Id*. at 21-22.
77 *Id.* at 10 (emphasis added).
78 D.19-10-001, at O¶ 3.
79 *See Assigned Commissioner's Scoping Memo and Ruling*, Application (A.) 23-05-010 (Sept. 5, 2023), at 5-6.

actions plainly demonstrate that setting the RA MPB, and thus the PCIA revenue requirement, is a process in which "many variables are taken into account and broad policy is formulated."[80]

3. The Change in Methodology Has a Significant Impact on Customers and LSEs and Would Not Have Occurred in Due Course, Meeting the Second *Edison* Requirement

Overall, the impact of the retroactive application of the RA MPB is significant. The courts and the Commission have been reluctant to find prohibited retroactive ratemaking has taken place when the retroactive rates have little impact. In *Edison*, the Court emphasized how using recorded actuals to calculate the refund was simply another way of balancing overcollections or under-collections for fuel costs that would have naturally occurred under the weather averaging method used in the original methodology.[81] As a result, the Court determined, the Commission's order left the utility no worse and no better off than it would have been had the Commission not ordered the refunds.[82] Similarly, the Commission has been reluctant to find prohibited retroactive ratemaking when a revised rate has no real impact compared to an existing rate.[83]

While *Edison* did not result in the "disruptive financial consequences of true retroactive ratemaking,"[84] the same cannot be said for the CCAs and departed customers if the Commission retroactively applies a revised RA MPB. The reason is, in part, due to the difference between market costs and market values, and the proxy nature of the RA MPB. In *Edison*, the Court relied

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80 *See Edison*, 20 Cal.3d at 828.

81 *Id.* at 824-827.

82 *Id.* at 824-826 (stating "Inasmuch as the two methods achieve the identical result – a final balancing of fuel clause over- and under-collections – and Edison itself embraces the former, the commission rightly concluded that it has not subjected Edison to retroactive ratemaking by choosing the latter because of a perceived need to institute the new energy clause without delay.").

83 *See* 1982 Cal. PUC LEXIS 1270 (Apr. 28, 1982) (No Original Decision Number) (concluding that including past franchise fees in the utility's rate adjustment did not constitute retroactive ratemaking because the revised practice would not have produced a different result from the existing practice); *see also* D.04-03-041, 2004 Cal. PUC LEXIS 80, *15 (Mar. 17, 2004) (rejecting challenges to a revision to the procedures for recovering expenses from water balancing accounts because they had no direct or indirect effect on rates).

84 *Edison,* 20 Cal.3d at 824-826.

heavily on both the mathematical nature of the refunds and the fact they were calculated based on "empirical data" and figures "definitively established by reference to the utilities' books."[85] In other words, no complicated formula or methodology was needed to calculate what the actual costs of fuel were: they were what the IOUs paid, as entered in their accounting books.

Here, however, the Commission must wrestle with the more nebulous concept of the "portfolio value" of capacity, a concept that is not definitively set in, and cannot be solely derived from, the IOUs' accounting books. Instead, capacity portfolio value relies on the RA MPB, an administratively determined proxy used to assess the value of capacity within the IOUs' portfolios.[86] Since this proceeding aims to revise the RA MPB itself, the Commission will not simply be comparing forecasted capacity value to actual capacity value; it will be revising what constitutes actual capacity value. And that was a contentious issue in Track One. Some parties argued the capacity value of the IOUs' portfolio is best measured via the short-term market value at which RA can be sold today.[87] Others argued older market transactions from five, ten or twenty years best reflect the capacity value of an IOU's portfolio.[88] Thus, unlike in *Edison*, the "truth" of the value of retained capacity *itself* is in dispute. No clear, easily verifiable actual market value of retained capacity exists to compare to the forecasted value.

Because portfolio market value is a subjective value, the shift in the revenue requirement that will come from using a revised RA MPB would not have occurred naturally, as a matter of

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85 *Id.* at 828-829.

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

87 *See* CalCCA OIR Opening Comments, at 25-31; CalCCA OIR Reply Comments, at 15-18; DACC/AReM OIR Opening Comments (Mar. 18, 2025), at 3-5; DACC/AReM OIR Reply Comments (Apr. 2, 2025), at 4; Shell OIR Reply Comments (Apr. 2, 2025), at 5-6; CLECA OIR Reply Comments, R.25-02-005 (Apr. 2, 2025), at 4.

88 *See* Joint IOU OIR Opening Comments, at 15-18 (Mar. 18, 2025); Joint IOU OIR Reply Comments (Apr. 2, 2025), at 11-16; TURN OIR Opening Comments (Mar. 18, 2025), at 1-3.

course, over time. When truing up an apple with an orange, it is not possible for the orange to be the natural evolution of the apple. That is, unlike in *Edison*, a new RA MPB methodology cannot naturally leave CCAs and customers in the same place as the old RA MPB would have left them.

The forced change to the 2025 PCIA revenue requirement will have a substantial impact on customers and LSEs. The Staff Report models the impact on the RA MPB of each of its proposals, which, all other things equal, are likely to significantly increase rates for CCA customers.[89] Staff determined that expanding the transaction data set to rely on data from 2020 - 2024 to calculate a combined RA MPB would cause a roughly 62 percent decline in the 2025 Forecast RA MPB. When the IOUs use capacity from their PCIA portfolios to meet compliance requirements for bundled customers, that capacity is valued as Retained RA, and the value is credited against the PCIA revenue requirement. The amount of capacity used by the IOUs is significant – the Joint IOUs disclosed that they met between 61 and 100 percent of their monthly RA requirements using PCIA resources. At that level of Retained RA capacity, a decline in the RA MPB as significant as the one proposed by Staff would cause a significant increase to the PCIA revenue requirement and the rates CCA customers must pay.

Such increases do not come without consequences. One of the reasons for the policy against retroactive ratemaking is to avoid surprises in the cost of electricity for customers. Given the substantial impact the modified RA MPB will have to the PCIA revenue requirement, applying the new MPB midstream in the 2025 ERRA process will have significant impacts well beyond those of a routine ERRA true-up. These substantial impacts – to both customers and CCAs – are distinguishable from the refunds in *Edison* that left SCE no better or worse off than it would have been.

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[89] Staff Report, at 13-18.

4. The Commission's Conclusion That Modifying the PCIA Is Not General Ratemaking Ignores the Function of the Rulemaking and its Predecessors

The Commission's conclusion that modifying the PCIA is not general ratemaking ignores the similarities between the PCIA ratesetting proceeding and other ratesetting proceedings such as the GRCs. The creation of the current PCIA framework was the result of several major Commission decisions and a multi-year rulemaking process.[90] The Commission designated those past PCIA rulemakings (and its present rulemaking amending those rulemakings) as the avenue for determining which costs the PCIA recovers, how to allocate those costs among customers, and how to design rates to effectuate cost recovery.[91] The Decision's determination that the Decision is not general ratemaking leads to the conclusion that none of the PCIA rulemakings set general rates and, in fact, the PCIA is never subject to "general ratemaking." That defies logic.

The Decision and its predecessors establish the PCIA *calculation methodology* used in the ERRA Forecast proceedings to determine annual rates. The PCIA rate, like other rates, appears as a separate line item on the utility bill[92] and requires the same three basic ratemaking steps used to establish other rates. The PCIA rulemakings accomplished the same policymaking tasks for the PCIA as a GRC accomplishes for other rates. Indeed, the classification of the PCIA rulemakings as "ratesetting[s]" under Commission Rule 1.3(g) given "mechanism[s] that in turn sets the rates for a [IOU]" clearly demonstrates that the PCIA proceedings sets "general rates."[93]

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[90] *See, e.g.,* R.17-07-026, D.18-10-019, and D.21-05-030.

[91] *See*, *e.g.*, R.17-07-026; *see also* D.06-07-030, *Opinion Regarding Direct Access and Departing Load Cost Responsibility Surcharge Obligations*, R.02-01-011 (July 20, 2006); D.18-10-019; D19-10-001; *and* D.21-05-030.

[92] D.20-03-019, at 21.

[93] Commission Rule 1.3(g).

Comparing the PCIA ratesetting process with the GRC process illuminates the point, including the three foundational GRC steps:

- <u>Step 1: Revenue Requirement.</u> In a GRC, the Commission begins by determining what costs should be recovered for a particular function or rate, *i.e.*, the size of the pie. For many costs, this occurs in GRC Phase 1. While this step was originally largely conducted in Phase 1 of the IOU GRCs, many costs today are recovered and rates set in other proceedings.[94] For purposes of the PCIA, the rulemakings have determined what costs are PCIA-eligible and should be included in the PCIA revenue requirement. For example, D.18-10-019 determined utility-owned generation was PCIA eligible and required the utilities to includes those costs and market values in the PCIA.[95]
- <u>Step 2: Revenue Allocation.</u> Next, the Commission divides the pie. For many costs, this occurs in GRC Phase 2. The Commission determines what portion of the identified costs is recovered from each customer class or type. For purposes of the PCIA, the rulemakings have determined how to separate the PCIA revenue requirement between bundled and unbundled customers. For example, the Decision revises the formula for calculating the RA MPB, decreasing the value of the IOUs' portfolios and increasing the costs allocated to unbundled customers, all other things equal.

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[94] *See, e.g.,* D.21-06-035, *Decision Requiring Procurement to Address Mid-Term Reliability (2023-2026),* R.20-05-003 (June 30, 2021), at 97 ("To the extent that any resources procured in response to this order are subject to allocation using the power charge indifference adjustment (PCIA), the date of that adjustment shall be vintaged by the date of this order").

[95] *See* D.18-10-019, COL 12, at 157 ("Including the costs of pre-2022 Legacy UOG within the PCIA is consistent with AB 117 and SB 350").

- Step 3: Rate Design. Finally, the allocated revenues are turned into a rate that is recovered from customers as a usage, fixed or demand-related charge. For many costs, this occurs in GRC Phase 2. With respect to the PCIA, the rulemakings have determined PCIA rates are set on a usage basis and recovered based on the vintage of both the resource and the customer.

If it looks like a duck, walks like a duck and quacks like a duck, it must be a duck. If rates established in the GRC are considered general ratemaking, this ratesetting and its predecessors, which fix the rules to establish the PCIA rates in the ERRA Forecast proceedings, must also be general ratemaking.

The process for PCIA ratemaking in the ERRA Forecast proceedings also aligns fully with the GRC process. While the GRCs set the revenue requirements, cost allocation and rate design for the test year and the following attrition years, the utilities' year-end consolidated advice letters implement the GRC decisions and update those formulae with the most recent data. For example, each utility's annual consolidated rate change advice letter not only includes true-ups to GRC-related balancing accounts, it also updates distribution rates based on the GRC's forecasted attrition values. The ERRA proceedings are similar, implementing prior Commission decisions to set PCIA rates using existing formulae with the most recent data. While the ERRAs accomplish the same end for the PCIA as the GRC's implementing advice letters accomplish for other rates, the PCIA rulemakings accomplish the same end for the PCIA as the GRCs accomplish for other rates: ***general ratemaking***.

The Commission itself has stated as much. The Commission has rejected attempts to address "general policy issues regarding PCIA ratemaking" in GRCs, claiming that is out of scope, cannot be revised in a GRC, and is "more appropriately considered in a Commission rulemaking."[96] And while the Commission has made clear that the Commission sets the PCIA in the ERRA proceedings,[97] ERRA proceedings are "intended to function as an individual electric IOU's annual forecast and accounting review, not as a forum for evaluating or setting policy."[98] As it pertains to the PCIA, the purpose of the annual ERRA Forecast proceedings, according to the Decision, is to simply put new values into existing formulae to determine indifference.[99]

If this is not the forum in which general rates are set for the PCIA, what is? It is simply counterintuitive to find that a rate methodology determined in this ratesetting proceeding, to be deployed in the ERRA Forecast proceedings, is not general ratemaking when it would be general ratemaking if incorporated into a GRC. The Decision therefore errs by failing to find that these proceedings setting the PCIA and determining methodological questions are "general ratemaking."

B. The Commission Applied the New Methodology Retroactively

Notwithstanding numerous parties' arguments in opposition, the Commission applies this new methodology retroactively to the 2025 Final RA MPB:

> We find that it would be inconsistent with the statutory mandate to ensure indifference to make the above findings, yet prohibit the adopted remedy from being applied immediately. Accordingly, the Energy Division is directed to apply the new methodology in the calculation of the 2025 Final RA MPB and in succeeding forecast and final MPBs.[100]

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96 *See* A.23-05-010, at 5-6 (allowing the question of vintaging of specific resources into scope but pushing "general policy issues regarding PCIA ratemaking methodology, such as consideration of a PCIA vintaging framework for use in future GRCs," into "a Commission rulemaking" and finding that they were "not within the scope of this [GRC].")

97 *See* OIR, at 12.

98 *Id.* at 10.

99 *See id*. at 29.

100 *Id.* at 29-30.

In applying the new methodology to the calculation of the 2025 Final RA MPB, the Commission uses a different methodology to conduct the 2025 true-up than it used to set the 2025 forecast revenue requirement.[101] In other words, it changes the methodology for calculating the 2025 revenue requirement ***after*** it has begun to recover the revenue requirement in rates effective at the beginning of 2025.

An example helps illustrate why this change is both retroactive and problematic. Imagine a car mechanic gives a customer a $500 estimate to replace the customer's brakes based on the anticipated cost of the parts and the typical time it takes to complete the job. The job turns out to take less time than anticipated because the customer has maintained the car well, and the price of the parts has decreased due to the lifting of recently imposed trade tariffs. For these reasons, the final bill is $400, which the customer happily pays. Between the calculation of the estimate and the actual cost, the formula to calculate the customer's bill has not changed (parts and labor); only the inputs to that formula have changed, in this case to the customer's advantage. This approach is akin to a typical true-up in the ERRA Forecast cases: forecasted net costs and revenues are trued up with actual costs and revenues, and customers pay the difference via the year-end PABA balance. While the inputs to the PCIA revenue requirement change (*e.g.*, the RA MPB increases or decreases), the formula used to calculate the revenue requirement stays the same (*i.e.*, the data window does not change from that prescribed when the estimated rates were set).

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[101] The 2025 ERRA Forecast cases for the three IOUs were set in Decisions issued at the Commission's December 19, 2024, meeting. *See* D.24-12-038, *Decision Approving Pacific Gas and Electric Company's 2025 Energy Resource Recovery Account Related Forecast Revenue Requirement and 2025 Electric Sales Forecast*, A.24-05-009 (Dec. 19, 2024); D.24-12-039, *Decision Approving Southern California Edison Company's 2025 Energy Resource Recovery Account-Related Forecast Revenue Requirement*, A.24-05-007 (Dec. 19, 2024); and D.24-12-040, *Decision Approving San Diego Gas & Electric Company's 2025 Electric Procurement Revenue Requirement Forecasts, 2025 Electric Sales Forecast, and Greenhouse Gas Related Forecasts*, A.24-05-010 (Dec. 19, 2024).

Not so with the Decision. The Decision is more akin to the following situation: the same car mechanic gives the same customer the same $500 parts-and-labor estimate. The job turns out to take less time and expense for the same reasons as above and would have resulted in a $400 bill under the parts-and-labor methodology. However, while the mechanic is fixing the customer's car, the mechanic's repair shop implements a new policy that requires all brake replacements to cost $700 regardless of the cost of the parts and the amount of labor used to conduct the repair. Thus, even though the service provided was only worth $400 under the methodology used to set the estimate, the mechanic has now decided the service is worth $700, and charges the customer that amount, a deeply unfair result almost certain to lead to an unhappy customer. This result is the same as that under the Decision – the Commission has retroactively modified the methodology used to set the RA MPB and PCIA rates in 2025, resulting in a significant dollar increase in costs for departed customers.

This dichotomy between the forecast and true-up, and the need for a consistent methodology between the two, was extensively discussed and is the subject of significant negative commentary by several parties.[102] DACC/AREM pointed out that application of the new methodology should be prospective, only, in part because applying the new methodology to the 2025 revenue requirement would be impractical, burdensome, and confusing.[103] Sonoma Clean Power noted the significant increase in risk attendant on applying the methodology to the 2025 ERRA Forecast true up.[104] CalCCA also commented that the change in methodology will result in a significant erosion in customer confidence in the Commission's established rates.[105]

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102 *See* DACC/AReM PD Opening Comments (June 12, 2025)); Sonoma Clean Power PD Opening Comments (June 12, 2025); CalCCA PD Opening Comments (June 12, 2025).

103 DACC/AReM PD Opening Comments, at 5.

104 SCP PD Opening Comments, at 3.

105 CalCCA PD Opening Comments, at 14.

Most importantly, however, is that by retroactively applying the redesigned RA MPB, which is a "general rate" under *Edison* as discussed above, the Commission has violated section 728 in contravention of its jurisdiction and California law.

V. THE COMMISSION FAILED TO PROCEED IN THE MANNER REQUIRED BY LAW BY NOT HARMONIZING SECTION 728's PROHIBITION ON RETROACTIVE RATEMAKING WITH THE INDIFFERENCE STATUTES

The Decision attempts to justify its retroactive application of the new RA MPB on the basis of the Commission's "specific mandate to ensure neutrality under Sections 365.2 and 366.2"[106] The Commission also states that:

> We find that it would be inconsistent with the statutory mandate to ensure indifference to make the above findings, yet prohibit the adopted remedy from being applied immediately. Accordingly, the Energy Division is directed to apply the new methodology in the calculation of the ***2025 Final RA MPB*** and in succeeding forecast and final MPBs."[107]

While the Decision recognizes that "[u]nder CalCCA's formulation, the Supreme Court's finding that Section 728 includes a general prohibition on retroactive ratesetting is in conflict with the specific mandate to ensure neutrality" under the indifference statutes, the Commission justifies ignoring section 728 by applying the new RA MPB to the 2025 revenue requirement by stating that doing so would be "inconsistent" with its statutory mandate to ensure indifference.[108] However, the court of appeal has noted that avoiding a conflict between two statutes, rather than prioritizing one statute over another, is preferred: "[w]hen two statutes potentially conflict, our first task is not to declare a winner, but instead to find a way, if possible, to avoid the

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106 Decision, at 27.

107 *Id.* at 27, COL 10, at 31 ("[t]he changes adopted should be applied to the calculation of the 2025 Final and 2026 Forecast RA MPB"), and O¶ 2, at 31 ("[t]he methodology adopted in the decision shall be effective immediately").

108 *Id.* at 27.

conflict."[109] Given the Commission can harmonize section 728 and the indifference statutes by only applying the redesigned RA MPB prospectively, the Decision errs in failing to harmonize these statutory provisions.

The Decision concludes, erroneously, that the requirements of section 728, as interpreted by the California Supreme Court, do not prohibit the application of the new calculation methodology for the RA MPB retroactively to the 2025 ERRA Forecast true-up. The Decision relies on its own, unreasoned reading of *Edison*. It determines that, contrary to CalCCA's contention, the case's prohibition on retroactive ratemaking does not apply in this instance because it does not set general rates:

> The *Edison* decision emphasized that the court's 1965 decision interpreting Section 728 as a prohibition against retroactive ratemaking was not intended to apply to every situation where action by the Commission results in retroactive application. The principle only applies to setting general rates. This OIR proceeding, and this decision, do not set general rates.[110]

A central objective of statutory construction is to interpret provisions to give effect to them all.[111] Another longstanding principle requires that statutes must be interpreted "with reference to the entire scheme of law of which it is part so that the whole may be harmonized and retain effectiveness."[112]

As CalCCA has noted, there is an obvious reading that harmonizes the prohibition on retroactive ratemaking with the Commission's desire to promote indifference. The prohibition on retroactive ratemaking would not be compromised by the application of the new RA MPB calculation methodology only ***going forward beginning in 2026***. Sections 728, 365.2, 366.2, and

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109 *Newark Unified School District v. Sup. Ct.* (2015) 245 Cal.App.4th 887, 904.
110 Decision, at 29.
111 *Walker v. Sup. Ct.* (1988) 47 Cal.3d 112, 131.
112 *Clean Air Constituency v. State Air Resources Bd.* (1974) 11 Cal.3d 801, 814.

366.3 can easily be harmonized, and both given effect, if the Decision simply applies the new calculation methodology to the 2026 Forecast RA MPB, and future ERRA Forecast proceedings, but not the 2025 Final RA MPB.

Finally, the impact of the Commission's discarding of section 728 through its brief attention to the retroactive ratemaking issue to prioritize the indifference mandate should be noted. Taken to its logical conclusion, the Commission's determination that it is not bound by section 728 when setting the PCIA means it can change PCIA revenue requirements as far back as it wants. This undermines any confidence parties can have in the stability of the Commission's past and future decisions establishing the PCIA. In other words, there will be no limit to stakeholders' ability to revive past arguments regarding prior PCIA determinations—all past vintages and all prior years may be open to challenge, and retroactivity is fair play so long as the Commission makes its changes outside of the GRC. Instead, the Commission should avoid this negative precedent by harmonizing the two statutory mandates through applying the redesigned RA MPB only prospectively to the 2026 ERRA Forecast.

VI. THE COMMISSION FAILED TO SUPPORT ITS DECISION WITH FINDINGS AND FAILED TO MAKE FINDINGS SUPPORTED BY SUBSTANTIAL EVIDENCE IN LIGHT OF THE WHOLE RECORD

The Commission failed to support the Decision with findings, as required by section 1757(a)(3), and failed to support its findings with substantial evidence in light of the whole record, as required by section 1757(a)(4). First, the Commission states in Finding of Fact (FOF) 1 that "[t]he Commission's current RA MPB calculation is flawed and vulnerable to manipulation."[113] Then, in the body of the Decision the Commission states that "[w]e find that it would be inconsistent with the statutory mandate to ensure indifference to make the above

113 Decision, FOF 1, at 28.

findings [related to the flawed RA MPB], yet prohibit the adopted remedy from being applied immediately."[114] The Commission, however, failed to support the Decision to apply the redesigned RA MPB retroactively by failing to make findings consistent with the *Edison* analysis – i.e., ***supporting*** why the Decision does not set general rates. The finding underlying the potential lack of indifference and the "fix" of the redesigned RA MPB, that "[t]he changes adopted herein work to improve the dataset and the RA MPB calculations," also fail to support the Decision to apply the redesigned RA MPB retroactively.

In addition, findings related to the alleged flaws of the current RA MPB are not based on substantial evidence. Instead, the findings are based on a slim record that CalCCA questioned throughout Track One. In fact, the Commission relied entirely on the Staff Report for its factual findings.[115] Several Parties, including CalCCA, requested data from Energy Division supporting its conclusions in the Staff Report throughout this process.[116] 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. A comprehensive review of the impact of the Decision is still not possible.

This bootstrapped conclusion from a circular argument does not meet the requirement that the Commission's Decision—to apply the RA MPB to the true-up of the 2025 ERRA proceedings—must be supported by sufficient evidence when considered in light of the whole

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[114] *Id.* at 27.
[115] *Id.* at 11.
[116] *See* CalCCA PD Opening Comments, at 5-6; CalCCA OIR Reply Comments, at 14-15; Ava Community Energy PD Opening Comments (June 12, 2025), at 5.

record. Both the findings, and the record, are insufficient to justify a retroactive application of the RA MPB.

VII. THE COMMISSION SHOULD SET ORAL ARGUMENT TO CONSIDER THIS APPLICATION FOR REHEARING

CalCCA seeks oral argument on this AFR under Rule 16.3 to "materially assist the Commission in resolving the application," and "demonstrate that the application raises issues of major significance for the Commission."[117] Such issues of major significance exist when the Commission's decision: (1) "adopts new Commission precedent or departs from existing precedent without adequate explanation"; (2) "changes or refines existing Commission precedent," (3) "presents legal issues of exceptional controversy, complexity, or public importance," or (4) "raises questions of fist impression that are likely to have significant precedential impact."[118]

Oral argument will materially assist the Commission in resolving this AFR. The underlying PCIA regulatory ecosystem is complex (involving RA MPBs, Indifference Amounts, the portfolio allocation balancing account, ERRA proceedings using different underlying data, and more). Tracing the Decision's impacts through this interlocking web is difficult. There are many intricacies to identifying the size, importance, and legal relevance of the numerous unintended consequences in which the Commission's various actions could result. These kinds of challenges—exploring grey areas, hypotheticals, the existence of alternatives, unintended consequences, and how to balance competing interests—are better handled in the dynamic give and take of an oral argument than by simply relying on paper submissions.

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[117] Commission Rule 16.3.

[118] *Id.,* 16.3(a)(1)-(3).

This AFR also warrants oral argument because it concerns issues of major significance. First, the Decision departs from existing precedents on retroactivity[119] without sufficiently explaining or distinguishing them. Second, even if the Commission believes it adequately explained its reasoning, the Commission radically departs from established standards regarding retroactive ratemaking. Third, this Application raises issues of major significance. The parties presented the Commission with vigorous disagreements on the retroactivity issue, and there was significant public interest in the Decision and its impacts. In addition, the legal issues raised by the Decision are exceptionally complex – requiring an analysis of the operation of the PCIA, how the MPB for RA is calculated, and all the various Commission decisions and policies that feed into the PCIA, and how retroactivity interacts with it. And fourth, the Decision raises questions of first impression regarding how retroactivity should be harmonized with the indifference requirement and whether the Commission believes there are any limits on retroactive ratemaking for PCIA-related rates.

For these reasons, oral argument is appropriate under Commission Rule 16.3, and the Commission should grant CalCCA's request to hold oral argument on this AFR.

VIII. CONCLUSION

For the foregoing reasons, CalCCA respectfully requests that the Commission grant this AFR and permit oral argument on the issues raised therein. It should issue an order correcting the specific unlawful and erroneous statements this AFR identifies in the Decision and not apply the new methodology to the 2025 PCIA revenue requirement.

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119 *See* CalCCA Opening Brief, at 7, and n. 32.

Respectfully submitted,

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION
1121 L Street, Suite 400
Sacramento, CA 95814
Telephone: (510) 982-2537
E-mail: regulatory@cal-cca.org

Respectfully submitted,

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

On behalf of
CALIFORNIA COMMUNITY CHOICE ASSOCIATION

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