NOVEMBER FILINGS

Comments on Oct 16, working group session 10

Initiative: Demand and distributed energy market integration

Comment period

Oct 21, 2025, 08:00 am - Nov 06, 2025, 05:00 pm

Submitting organizations

California Community Choice Association

California Community Choice Association

Submitted on 11/06/2025, 12:04 pm

Contact

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

1. Please provide your general feedback on the session, structure and direction the Demand and Distributed Energy Market Integration working group meeting on Oct 16, 2025.

The California Community Choice Association (CalCCA) appreciates the opportunity to comment on the October 16, 2025, meeting of the Demand and Distributed Energy Market Integration (DDEMI) Working Group (WG). CalCCA recommends that the CAISO take the following actions related to the issues and topics discussed at the WG meeting:

- Modify problem statement three for the Distributed Energy Resources Aggregations (DERA) market participation model to eliminate the implication that the California Independent System Operator (CAISO) and the California Public Utilities Commission (CPUC) must sequentially address modifications to existing methodologies for determining resource adequacy (RA) eligibility;
- Modify DERA problem statement six, which addresses separate resources located at a single service account participating in separate aggregations, to clarify that it applies to retail and wholesale market participation models beyond DERA and that it is a concern for all aggregators and program administrators; and
- Include regulatory and implementation assessments of discussion topic two, Economic-Based Demand Response (DR) Participation Model, problem statement two, which highlights the use of device-level metering. These assessments should address modifying the CAISO's systems and processes to accommodate less accurate, device-integrated meters and telemetry, and applying a discount factor to the metered performance to compensate for the lower degree of accuracy.

2. Do the six problem statements accurately reflect the challenges facing DER participation?

CalCCA generally supports the six problem statements for the DERA market participation model, but with modifications to problem statements three and six.

First, problem statement three addresses the lack of a pathway for DERAs to qualify for RA, citing the need to address this issue at both the CAISO and the CPUC. CalCCA agrees and notes that the inability to provide RA is one of the primary barriers to DER expansion. However, the problem statement implies that the actions of the CAISO and the CPUC must be sequenced to resolve the RA counting issue. While the CAISO and the CPUC each have separate jurisdictional responsibilities regarding the qualification of DERAs for RA, activities to modify these processes do not need to occur sequentially. In other words, the CAISO should not wait for the CPUC to develop a Qualifying Capacity (QC) methodology before addressing changes to deliverability, visibility, and Net Qualifying Capacity (NQC) methodologies. The reverse is also true. The CPUC does not need to, nor should it, wait for the CAISO to address deliverability issues and NQC methodologies before developing its own QC methodology. Given that RA accounting is a high priority for DER participation, the CAISO and the CPUC should both begin to make progress on their respective responsibilities so that all outstanding issues can be addressed in a time-efficient manner.

CalCCA recommends that problem statement three be revised to eliminate the implication that the issue needs to be addressed sequentially by the CAISO and the CPUC. The following revision to problem statement three should be made, with deletions in strikethrough and additions in **bold:**

> There is currently no pathway for DER aggregations (DERAs) to qualify for resource adequacy, and this is a multi-agency issue needing the CAISO's attention because the CAISO would need to address or help resolve some issues (including deliverability determination and visibility) before the CPUC would develop a Qualifying Capacity methodology, as well as because the CAISO needs to develop Net Qualifying Capacity methodologies **resolving this issue requires the attention of both the CAISO and the CPUC. The CPUC would be responsible for developing a new Qualifying Capacity methodology, while the CAISO would be responsible for developing its deliverability assessment and the Net Qualifying Capacity methodology for these resources. Coordination between the CAISO and the CPUC would be necessary to address these and other issues, such as ensuring the required level of visibility into DERAs participating in the CAISO markets. However, these issues can be addressed by the CAISO and CPUC simultaneously.**

Second, problem statement six, which highlights the concern about separate resources at a single site participating in separate aggregations, also applies to other market participation models beyond DERA and is a concern for all aggregators and program administrators. The example included in problem statement six highlights the potential conflict between the DERA and Proxy Demand Response (PDR) economic DR participation models. CalCCA notes that this same concern applies to the conflicting operations of DERs enrolled in any other market participation models, as well as to DER participation in wholesale and retail markets. In addition, the problem statement states that "utilities may be concerned that the battery operation for DERA participation impacts the other program." These concerns extend beyond just utilities and their programs. Other aggregators, including CCAs and third-party entities, will be affected by this issue.

CalCCA recommends that problem statement six be rephrased to clarify that it applies to any aggregator or program administrator, and that the problem statement's concern can occur with any other market participation model at the wholesale and retail levels. CalCCA suggests the following revision to problem statement six, with deletions in strikethrough and additions in **bold:**

> Where separate resources at a single site participate in separate aggregations, such as a battery participating in a DER aggregation while the whole home using smart thermostat and heat pump water heater participates in a PDR, utilities **aggregators and program administrators** may be concerned that the battery operation for DERA participation impacts

the other program. **This concern applies to aggregations in other wholesale market participation models, as well as in retail markets.**

3. Are there any additional considerations to the ISO assessment for the captured problem statements

Problem statement two, under discussion topic two, Economic-Based DR Participation Model, describes the administrative and cost barriers related to the current revenue-grade metering requirements that restrict the ability to use device-level metering on individual resources within an aggregation. The CAISO provided a policy assessment for this problem statement, but did not offer regulatory or implementation assessments. CalCCA recommends incorporating the following regulatory and implementation assessments for problem statement two to ensure the CAISO can adequately and fairly address this issue:

> **Regulatory**: Device-integrated meters are less accurate than revenue-grade meters. Allowing the use of device-integrated meters for measuring the performance of inverter-based DERs and smart appliances may require the CAISO to apply a discount factor to compensate for the lower accuracy of these meters to avoid over-compensating participating customers. The CAISO would need to clarify further and discuss with stakeholders the mechanism for applying the discount factor, so that both the CAISO and stakeholders can fully understand and assess the regulatory impacts of this change (*i.e.*, tariff impacts, the need to coordinate with LRAs, etc.).
>
> **Implementation**: Implementation of device-integrated meters would require the CAISO to modify its metering requirements to allow device-integrated, non-revenue-grade metering and telemetry for smart appliances, such as thermostats, heat pumps, and heat pump water heaters, as well as inverter-based DERs. The CAISO would also need to modify its systems to allow for the discounting of metered performance data, compensating for the less accurate device-integrated meters.

4. Additional comments, include any other feedback not captured above.

CalCCA has no additional comments or feedback at this time.

Comments on Oct 16, working group session 10

Initiative: Demand and distributed energy market integration

Comment period

Oct 21, 2025, 08:00 am - Nov 06, 2025, 05:00 pm

Submitting organizations

Marin Clean Energy

Marin Clean Energy

Submitted on 11/06/2025, 04:14 pm

Contact

MCE Regulatory (regulatory@mcecleanenergy.org)

1. Please provide your general feedback on the session, structure and direction the Demand and Distributed Energy Market Integration working group meeting on Oct 16, 2025.

Marin Clean Energy (MCE) appreciates the opportunity to comment on topics discussed during the October 16, 2025 working group meeting. We thank the CAISO team for outlining clear next steps in terms of a final Discussion Paper, followed by an Issue Paper and the corresponding comment opportunities. MCE looks forward to continuing to participate in the Policy Initiative Stakeholder Process for Demand and Distributed Energy Market Integration (DDEMI).

As this initiative moves forward, MCE recommends the CAISO:

- Provide additional regulatory, policy, and implementation details in the Discussion Paper to help stakeholders assess potential solutions, benefits, challenges, and prioritization of problem statements.
- Enable near-term pilots with independent measurement and verification to evaluate proposed or modified Performance Evaluation Methodologies (PEMs) and Proxy Demand Resource (PDR) models before formal tariff or BPM changes.
- Support expanded use of the control group methodology by allowing use of non-participant data for control group baselines without registration or opt-in, and by exploring use of prescriptive baselines that DR providers can adapt for their programs.

2. Do the six problem statements accurately reflect the challenges facing DER participation?

MCE generally agrees with the problem statements presented on the DER aggregation (DERA) participation model, including the proposed revisions discussed during the working group meeting.

- MCE encourages the CAISO to present revised problem statements that consider the respective jurisdictions and current proceedings of the CAISO and the CPUC, and to frame problem statements in a manner that enables flexible solutions and progress, rather than any particular sequencing of actions between the CAISO and CPUC.
- MCE also supports the inclusion of a problem statement addressing dual participation, but emphasizes that dual participation concerns extend beyond utility resources and the DERA model.

MCE looks forward to reviewing the revised problem statements in the Discussion Paper, and reserves the right to provide additional feedback on the final statements.

3. Are there any additional considerations to the ISO assessment for the captured problem statements

- **MCE strongly supports the CAISO's interest in expanding use of control group baselines due to their robust statistical methodology.**

The control group methodology can yield more accurate outputs and reduce exogenous distortions to customer baseline calculations, but its use is constrained by current rules, especially the requirement to register non-participant accounts for "matched" control groups.

- MCE encourages the CAISO to remove the registration or opt-in requirement for LSEs with existing access to non-participant data as an expeditious way to increase utilization of control group baselines.
  - For LSEs such as MCE, removal of the registration or opt-in requirement would directly resolve a significant barrier by allowing the use of their customers' data for non-participant control group formation.
- MCE encourages the CAISO to assess potential solutions for both LSE and third party aggregators, and to include additional assessment detail within the Discussion paper.
- MCE also encourages the CAISO to include additional assessment details for implementing the prescriptive baseline concept proposed by Leap, including a modified approach whereby a state entity, such as the CPUC, creates standardized state-level load profiles while leaving it to the demand response providers to calculate the baseline for their unique demand response programs.

MCE recognizes the FERC open access concern outlined in the regulatory assessment for this problem statement–that the CAISO "may be required to consider ability for third party aggregators to utilize non-registered control groups." However, MCE notes that such consideration should not preclude an expeditious and efficient solution for other parties, such as non-IOU LSEs. MCE encourages the CAISO to assess potential solutions for both LSE and third party aggregators, and to include additional assessment detail within the Discussion paper, while acknowledging that the ultimate solutions may somewhat differ.

As an LSE, MCE already has access to the requisite non-participant customer data – data which MCE already uses in CAISO settlements. MCE further appreciates that third party aggregators may in some instances face distinct challenges related to data access, which requires coordination with the CPUC to address. As stated above in our answer to Question 2, MCE encourages the CAISO to present revised problem statements that consider the respective jurisdictions and roles of the CAISO and CPUC, including the CPUC's ongoing proceedings addressing non-participant data access for third party aggregators.

Problem Statement 2.1

> MCE encourages the CAISO to implement pilots with independent measurement and verification to demonstrate the efficacy of proposals for a modified Proxy Demand Resource (PDR) model, and to add the necessary details for soliciting and authorizing said pilots within the final assessment outlined in the Discussion Paper.

MCE believes that pilots could be implemented in the near term by evaluating the performance of modified PDR designs while continuing to require adherence to existing rules and regulations for PDR. MCE is currently developing a framework for demonstrating the value of a modified PDR model that allows for some level of export from participating accounts with installed energy storage, which would increase participation and enhance overall performance of the PDR model. Piloting of MCE's approach, as well as other potential approaches to mPDR design and implementation, will help inform and support the CAISO's mPDR assessment and other necessary processes prior to seeking approval for revised tariffs, or updating BPMs.

4. Additional comments, include any other feedback not captured above.

MCE has no additional comments at this time. We look forward to reviewing and providing feedback on the Discussion Paper.

Attachments

MCE - DDEMI 10_16 StakeholderCommentTemplate .docx

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Update Distribution Level Interconnection Rules and Regulations	R.25-08-004

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON THE ORDER INSTITUTING RULEMAKING TO UPDATE DISTRIBUTION LEVEL INTERCONNECTION RULES AND REGULATIONS

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

November 10, 2025

TABLE OF CONTENTS

SUMMARY OF RECOMMENDATIONS[1]

CalCCA recommends the Commission:

- Prioritize reforms for electrical independence testing under Screen Q as recommended by many parties in Opening Comments, including IREC, CESA, SEIA, and SDG&E; and

- Reject PG&E's and SCE's recommendations to remove from the scope of the OIR the topic of ensuring the IOUs' practices and processes comply with the requirement to utilize ICA values in conducting Rule 21 screens.

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

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Update Distribution Level Interconnection Rules and Regulations	R.25-08-004

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON THE ORDER INSTITUTING RULEMAKING TO UPDATE DISTRIBUTION LEVEL INTERCONNECTION RULES AND REGULATIONS

The California Community Choice Association[2] (CalCCA) submits these reply comments pursuant to Rule 6.2 of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure,[3] in response to the *Order Instituting Rulemaking to Update Distribution Level Interconnection Rules and Regulation*[4] (OIR), issued August 20, 2025, and the directives therein.

I. INTRODUCTION

Party Opening Comments[5] demonstrate general support for the Preliminary Scope as outlined in the OIR, with some amendments. CalCCA's Reply Comments respond to two topics

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

4 *Order Instituting Rulemaking to Update Distribution Level Interconnection Rules and Regulation*, Rulemaking (R.) 25-08-004 (issued Aug. 20, 2025): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M576/K867/576867418.PDF.

5 All references herein to party Opening Comments are to the Opening Comments filed in this proceeding, R.25-08-004, on or about October 20, 2025.

highlighted in party Opening Comments. *First*, parties representing investor-owned utilities (IOU) and the solar and energy storage industry, including the Interstate Renewable Energy Council (IREC), the California Energy Storage Alliance (CESA), the Solar Energy Industries Association (SEIA), and San Diego Gas & Electric Company (SDG&E), agree that reforming the Electrical Independence Test Screen Q (Screen Q) is a critical priority. Several of these parties propose near-term reforms, including increasing the threshold for Screen Q from one megavolt-amperes (MVA) to five MVA. Parties also offer recommendations for longer-term reforms or support for considering such reforms in a second phase of the proceeding.

Second, many parties highlight the need to improve IOUs' practices and processes for utilizing integration capacity analysis (ICA) values in conducting Electric Tariff Rule 21 (Rule 21) interconnection screens. However, Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (SCE) both recommend removing this topic from the scope of the OIR. Utilizing accurate and complete ICA data in the Rule 21 screens can help improve the efficiency of the interconnection process and potentially save developers from incurring unnecessary costs. While ICA reforms are also within the scope of the High DER proceeding,[6] the Commission should include this topic in the scope of this OIR to specifically address the use of ICA in the interconnection process.

As set forth below, CalCCA recommends the Commission:

- Prioritize reforms for electrical independence testing under Screen Q as recommended by many parties in Opening Comments, including IREC, CESA, SEIA, and SDG&E; and

6 *Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future* (High DER), R.21-06-017 (July 2, 2021): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M390/K664/390664433.PDF.

- Reject PG&E's and SCE's recommendations to remove from the scope of the OIR the topic of ensuring the IOUs' practices and processes comply with the requirement to utilize ICA values in conducting Rule 21 screens.

II. IREC'S, CESA'S, SEIA'S, SDG&E'S, AND OTHER PARTIES' RECOMMENDATIONS FOR REFORMS OF ELECTRICAL INDEPENDENCE PROCESSES UNDER SCREEN Q SHOULD BE ADOPTED

The Commission should prioritize reforms to electrical independence testing under Screen Q, as highlighted by many parties in Opening Comments, including IREC, CESA, SEIA, and SDG&E.[7] Parties identify high failure rates for projects going through Screen Q as a significant barrier for the interconnection of distributed energy resources (DER) and recommend that interim reforms be prioritized in a first phase of the OIR.[8] IREC states that "Screen Q is currently the single biggest obstacle to DER interconnection in the state,"[9] and CESA advances that "[i]nterim Screen Q reforms are urgently needed."[10] For its part, SDG&E states that "one of the most critical areas for reform involves the evaluation of electrical independence through Screens Q and R,"[11] and recommends eliminating Screen Q altogether.[12] CalCCA does not take a position on the removal of Screen Q in these Reply Comments, but acknowledges that SDG&E's recommendation to eliminate the screen underscores the importance and urgency of addressing Screen Q reforms.

CalCCA agrees that there is a pressing need for immediate reforms to Screen Q. One near-term reform cited by several parties involves raising the threshold that triggers a Screen Q

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[7] *See* IREC Opening Comments, at 2; CESA Opening Comments, at 4-17; SEIA Opening Comments, at 2-10; and SDG&E Opening Comments, at 1-7; *accord* Advanced Energy United (AEU) Opening Comments, at 4; California Solar and Storage Association (CalSSA) Opening Comments, at 25-26; and Coalition for Community Solar Access (CCSA) Opening Comments, at 3-11.

[8] *See* CESA Opening Comments, at 2; CalSSA Opening Comments, at 25; CCSA Opening Comments, at 1; and SEIA Opening Comments, at 2.

[9] IREC Opening Comments, at 2.

[10] CESA Opening Comments, at 4.

[11] SDG&E Opening Comments, at 1.

[12] *Id.* at 2-4.

review from one MVA to five MVA.[13] SEIA points out that the "market for [distributed generation] projects above one MW has stalled as projects are unable to achieve interconnection under Rule 21" as justification for the interim increase in the Screen Q threshold.[14] CESA provides the following rationale for increasing the threshold:

> Widespread failures at 1 MVA are evidence of flawed upstream transmission assumptions rather than a reflection of actual DER impacts on the grid. Raising the threshold would reduce the number of projects unnecessarily flagged by Screen Q while preserving the ability to study larger projects that may pose legitimate transmission concerns.[15]

Adopting interim measures, such as modifying the Screen Q threshold, may provide near-term relief for distributed generation projects seeking to interconnect with the grid. However, the Commission must also consider longer-term solutions to address the underlying causes of the high rate of projects failing this screen. Given the serious concerns about the high project failure rate, the Commission should prioritize reforms to Screen Q.

III. PG&E'S AND SCE'S RECOMMENDATIONS TO REMOVE THE UTILIZATION OF THE ICA FROM THE SCOPE OF THE OIR SHOULD BE REJECTED

PG&E's and SCE's recommendations to remove the utilization of ICA from the scope of the OIR should be rejected. PG&E argues that ICA is already being addressed in the High DER proceeding, and addressing it in the OIR "may create regulatory redundancies or contradictions."[16] SCE recommends removing it from the scope of the OIR since it "has discussed this topic in detail with the Commission and interconnection stakeholders in various

[13] *See* AEU Opening Comments, at 4; CCSA Opening Comments, at 9; CESA Opening Comments, at 6-7; CalSSA Opening Comments, at 26; and SEIA Opening Comments, at 2, 9-10.
[14] SEIA Opening Comments, at 9.
[15] CESA Opening Comments, at 7.
[16] PG&E Opening Comments, at 3.

forums."[17] These arguments overlook the importance of ensuring that accurate and timely ICA values are utilized correctly in Rule 21 interconnection processes and of identifying methods to enhance the usefulness of the ICA in these processes.

The Opening Comments of the Public Advocates Office at the California Public Utilities Commission (Cal Advocates) emphasize the need for this OIR to address IOU accountability for, among other things, the "accurate use of ICA data."[18] Cal Advocates goes on to suggest that the use of ICA in the Rule 21 interconnection process should be a high priority, since it "could provide opportunities to improve efficiency and reduce unnecessary costs."[19]

Other parties highlight specific improvements for utilizing the ICA in the Rule 21 interconnection process. CESA points to the need for the IOUs to "adopt consistent ICA calculation methodologies and data formats," and to "update ICA maps more frequently to reflect current system conditions and pending interconnection requests."[20] Similarly, IREC recommends "that the Commission broaden this topic to also include consideration of changes to Rule 21 that might better utilize the ICA to improve interconnection review and ensure the benefits of the analysis are being realized."[21]

The Commission should keep the topic of utilizing ICA values in the Rule 21 interconnection process within the scope of the OIR, as recommended by many parties as discussed above. The Commission should also closely coordinate these efforts with the High DER proceeding.

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17 SCE Opening Comments, at 13.
18 Cal Advocates Opening Comments, at 2.
19 *Id*. at 6.
20 CESA Opening Comments, at 18.
21 IREC Opening Comments, at 7.

IV. CONCLUSION

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

Respectfully submitted,

Leanne Bober,
Director of Regulatory Affairs and Deputy General Counsel

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

November 10, 2025

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Enhance Demand Response in California.	R.25-09-004

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING COMMENTS ON THE ORDER INSTITUTING RULEMAKING TO ENHANCE DEMAND RESPONSE IN CALIFORNIA

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

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

November 13, 2025

TABLE OF CONTENTS

TABLE OF AUTHORITIES

Other Authorities

California Public Utilities Commission Decisions

California Public Utilities Commission Proceedings

California Public Utilities Commission Rulings

SUMMARY OF RECOMMENDATIONS[1]

CalCCA provides the following recommendations in response to the Demand Response OIR:

- In addition to the OIR preliminary scoping items, the Commission should consider the following:
    - Developing new data systems and updating existing data systems because both will be critical to the success of demand response;
    - Developing strategies to reduce barriers to DR adoption;
    - Discussing RTP pilot evaluation results in this proceeding;
    - Revisiting the Demand Flexibility Staff Proposal to determine whether any updates are needed to the vision of dynamic rates as a DR resource;
    - Defining the DR landscape, its elements, types, and how those elements and types should be categorized to ensure stakeholders are on the same page; and
    - Defining cost-effectiveness inputs and tests in the context of DR and load flexibility to optimize DR resources to provide grid benefits and save customers money.
- The Commission should adopt the DR Guiding Principles with the following amendments:
    - Add customer choice and competitive neutrality among DR service providers to the DR goals originally adopted in D.16-09-056 and reiterated in the DR Guiding Principles; and
    - Revise DR Guiding Principles 3 so that it does not exclude behavioral DR programs and resources from being considered cost-effective.
- CalCCA does not object to the preliminary schedule or preliminary determination on categorization of the proceeding, but CalCCA recommends the Commission:
    - Estimate dates for staff proposals for all preliminary scoping items to provide a more detailed roadmap for stakeholders; and
    - Consider the potential for a separate ratesetting track to address potential changes to the CEC's LMS.

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

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

Order Instituting Rulemaking to Enhance Demand Response in California.	R.25-09-004

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING COMMENTS ON THE ORDER INSTITUTING RULEMAKING TO ENHANCE DEMAND RESPONSE IN CALIFORNIA

The California Community Choice Association[2] (CalCCA) submits these opening comments pursuant to Rule 6.2 of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure,[3] in response to the *Order Instituting Rulemaking to Enhance Demand Response in California*[4] (OIR), issued September 20, 2025, and the directives therein.

I. INTRODUCTION

Demand response (DR) – the adjustment in electricity consumption by customers in response to price signals and/or electrical grid conditions – is one of California's primary tools for minimizing costs of new resources and grid upgrades, maximizing value for customers, and

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

4 *Order Instituting Rulemaking to Enhance Demand Response in California*, Rulemaking (R.) 25-09-004 (issued Sept. 29, 2025): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M582/K072/582072320.PDF.

promoting reliability. Given the value of demand response and more broadly, demand flexibility, the California Energy Commission (CEC) has set a 2030 target of 7,000 megawatts of demand flexibility to make that amount of electricity available by shifting its use away from peak hours.[5]

CalCCA supports the Commission's overall goal in opening the OIR of seeking ways to more effectively harness the promise of DR by adopting or amending new DR policies and guidelines. The OIR includes a preliminary scope of issues to be addressed, including what guiding principles the Commission should adopt for DR policies. The preliminary scope also includes the adoption or amendment of policies related to making DR resources more "consistent, predictable, reliable, and cost-effective,"[6] including policies related to: (1) dual participation; (2) valuation methodologies and evaluation metrics; (3) California Independent System Operator (CAISO) market integration topics; and (4) Resource Adequacy (RA) valuation and slice-of-day (SOD) implementation. Finally, the scope includes the consideration of "standardized data systems, communication protocols, and data transfer processes . . . to support [DR] initiatives, including dynamic rates."[7]

CalCCA's comments herein respond to the Commission's three questions related to the OIR scope. *First*, the Commission invites comments on whether additional issues or details should be included in scope. *Second*, the Commission asks whether issues in other Commission proceedings require coordination with the rulemaking. *Finally*, the Commission asks whether the DR Guiding Principles staff proposal appended to the OIR should be adopted or modified. CalCCA addresses each of these questions in turn below.

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5 *See* CEC Docket 21-ESR-01, *SB 846 Load Shift Goal Commission Report* (May 26, 2023): https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=21-ESR-01.

6 OIR, at 9.

7 *Id.* at 10.

In response to the first two OIR questions, CalCCA provides the following six items to include in addition to the preliminary scoping items, some of which have been considered in other Commission proceedings. *First*, the Commission should ensure the scope of this proceeding considers not only the development of *new* data systems related to DR, but also necessary updates to *existing* data systems related to DR. While new data systems will be necessary to expand California's DR landscape, existing system updates are needed to accommodate new approaches to DR. These include the implementation of dynamic rates and programs by investor-owned utilities (IOU) and community choice aggregators (CCA) as contemplated by the CEC's Load Management Standards (LMS) regulations.[8]

Second, the Commission should consider how to overcome barriers to the adoption of DR to better inform the implementation of DR programs, including dynamic rates. Developing a list of barriers to DR adoption and proposing methods to overcome those barriers fits well in the theme of this proceeding of enhancing DR. DR itself is not new, but as time goes on, new types and approaches to DR emerge, bringing new challenges for both DR providers and customers. Reducing these barriers will help customers achieve the benefits of DR and will support California's load shifting goal.

Third, the Commission should consider and discuss the real-time pricing (RTP) pilot evaluations that will be provided following the conclusion of Pacific Gas and Electric Company's (PG&E) and Southern California Edison Company's (SCE) RTP pilots on December 31, 2027. Since the Commission is proposing that this proceeding include topics such as dynamic rate data systems and processes, valuation methodologies, and evaluation metrics, this proceeding is the most relevant venue for the consideration of the RTP pilot evaluation results statewide.

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[8] 20 Cal. Code of Regulations (CCR) §§ 1621, 1623, 1623.1 (LMS Regulations).

Fourth, the Commission should revisit the Energy Division Staff Proposal on advanced demand flexibility management and customer distributed energy resource (DER) compensation (Demand Flex Staff Proposal).[9] The Demand Flex Staff Proposal provides a roadmap for demand flexibility dubbed the California Flexible Unified Signal for Energy (CalFUSE). Revisiting the Demand Flex Staff Proposal will allow any necessary updates to the CalFUSE roadmap resulting from insights gained from programs and pilots currently implementing DR and dynamic rates.

Fifth, the Commission should define the DR landscape now that it has become more diverse. Explicitly defining what is or is not a DR resource and any subtypes of DR resources will provide a shared language for all stakeholders to use, reducing confusion.

Finally, the Commission should define cost-effectiveness in the context of DR and load flexibility to better support California's load flexibility goals. Different approaches to DR may require different applications of cost-effectiveness tests and inputs, depending on their characteristics. As the DR landscape has evolved to include dynamic rates, updated Commission direction on cost-effectiveness is needed to evaluate specific programs, and also to determine optimally effective DR resources.

In response to the third OIR question, CalCCA supports the DR Guiding Principles staff proposal, with two amendments.

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[9] *Advanced Strategies for Demand Flexibility Management and Customer DER Compensation* (June 22, 2022): https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-response/demand-response-workshops/advanced-der---demand-flexibility-management/ed-white-paper---advanced-strategies-for-demand-flexibility-management.pdf.

First, the Commission should amend the DR Guiding Principles to incorporate customer choice and competitive neutrality among DR providers in the DR goals.[10] Fostering a landscape of DR providers that offer different programs will support customers in being able to choose the program that is right for them. Not only does this increase potential participation in DR and load shifting programs and customers' ability to save money, but it also increases the potential volume of load shifting and overall reductions.

Second, DR Guiding Principle 3 should not exclude DR programs or resources that rely on customer action, as its current form implies. The discussion supporting DR Guiding Principle 3 conflates metrics such as reliability and consistency with cost-effectiveness, which would automatically exclude programs or resources that rely on behavioral changes rather than automations. While automations will play a critical role in the success of DR programs and dynamic rates, human intervention and behavioral changes should not be excluded simply because they can be viewed as less reliable. This is especially true if the benefits do not outweigh the costs of installing automation technology.

In response to the OIR and as set forth below, CalCCA therefore recommends:

- In addition to the OIR preliminary scoping items, the Commission should consider:
    - Developing new data systems as well as updating *existing* data systems because both will be critical to DR's success;
    - Developing strategies to reduce barriers to DR adoption;
    - Incorporating a discussion of RTP pilot evaluation results in this proceeding;
    - Revisiting the Demand Flex Staff Proposal to determine whether any updates are needed to the vision of dynamic rates as a DR resource;
    - Defining the DR landscape, its elements, types, and how those elements and types should be categorized to ensure stakeholders are on equal footing; and

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[10] D.16-09-056, *Decision Adopting Guidance for Future Demand Response Portfolios and Modifying Decision 14-12-024,* R.13-11-011 (Sept. 29, 2016), at 97, Ordering Paragraph (O¶) 7: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M167/K725/167725665.PDF.

- Defining cost-effectiveness inputs and tests in the context of DR and load flexibility to optimize DR resources to provide grid benefits and promote customer affordability.

- The DR Guiding Principles should be adopted with the following amendments:
    - Add customer choice and competitive neutrality among DR service providers to the DR goals originally adopted in D.16-09-056[11] and reiterated in the DR Guiding Principles; and
    - Revise DR Guiding Principles 3 so that it does not exclude behavioral DR programs and resources from being considered cost-effective.

Finally, CalCCA does not object to the preliminary schedule or preliminary determination on categorization of the proceeding. However, CalCCA recommends the Commission:

- Schedule dates for any staff proposals for preliminary scoping items to provide a more detailed roadmap for stakeholders; and
- Consider the potential for a separate ratesetting track to address costs for CEC LMS implementation.

II. THE PRELIMINARY SCOPE SHOULD BE ADOPTED, WITH AMENDMENTS

A. The Commission Should Ensure the Scope of Standardized Data Systems Includes the Development of New Systems *and* Updates to Existing Systems

The Commission should ensure that Preliminary Scoping Item 3 regarding standardized data systems includes both the development of new systems and any needed updates to *existing* systems. Preliminary Scoping Item 3 asks:

> What standardized data systems, communication protocols, and data transfer processes should the Commission adopt or amend to support demand response initiatives, including dynamic rates?[12]

The use of the words "adopt or amend" does foreshadow that this proceeding will discuss both *new **and** existing* systems and processes. Indeed, this proceeding should not be limited to the development of only *new* data systems and data sharing processes when there is significant data infrastructure that already exists across the IOUs, CCAs, and service providers. Not all of this

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11 *Ibid.*
12 OIR, at 9.

existing infrastructure has been updated to meet the needs of the DR landscape that this proceeding seeks to address.

For example, CCAs have struggled with accessing timely and accurate billing-quality customer usage data as CalCCA extensively described in the Demand Flexibility OIR, R.22-07-005.[13] In fact, the Demand Flexibility Scoping Ruling's Issue 4 asked:

> 4. How should the Commission ensure access to dynamic electricity prices by bundled and unbundled customers, devices, distributed energy resources, and third-party service providers? What systems and processes should the Commission authorize for access to prices and responding to price signals?
>
> > a. What systems and processes should the Commission authorize for computation of dynamic prices for bundled and unbundled customers?
> >
> > b. What systems and processes should the Commission authorize to enable load serving entities to offer unbundled customers the option to take service on dynamic electricity prices?
> >
> > c. What systems and processes should the Commission authorize to enable third-party service providers (e.g., automation service providers, device manufacturers) to offer demand flexibility services to customers?
> >
> > d. What systems and processes should the Commission authorize to enable customers to optimize and pre-schedule their energy use to provide demand flexibility (e.g., forward transactions)?
> >
> > e. What are the costs associated with these systems and processes (for access to prices and responding to price signals), and how should these costs be recovered?

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13 *See e.g., California Community Choice Association's Comments on the Proposed Decisi*on, R.22-07-005 (Aug. 14, 2025), at 11-12 (detailing CalCCA's long-running advocacy for improving CCA data access to timely and accurate billing-quality customer usage data): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M576/K079/576079921.PDF.

> f. How should these systems and processes (for access to prices and responding to price signals) be managed and overseen (e.g., utility administration or third-party administration)?[14]

The Commission closed the Demand Flexibility proceeding without addressing these data system and data access issues, which are vital to the CCAs' ability to design and implement dynamic rates and comply with the CEC's LMS. Now, in the instant proceeding, CalCCA seeks to ensure these data issues are fully addressed.

In addition to enhancing existing data sharing processes for CCAs, the Demand Flexibility proceeding was also meant to develop a "Price Machine" to enable dynamic rate price signal deployment. The Price Machine was originally proposed in the Demand Flex Staff Proposal, issued before the Demand Flexibility proceeding was initiated in the summer of 2022.[15] The Price Machine would constitute a new data system to support real-time pricing rates offered by IOUs and CCAs. Similarly, the CEC envisions a Single Statewide Tool (SST) in the LMS, allowing third-party service providers to query customer rate identification numbers that correspond to dynamic rate data listed in the CEC's Market Informed Demand Automation Server (MIDAS) tool. IOUs, CCAs, and publicly owned utilities are responsible for developing the SST,[16] which would also constitute a new data system related to demand flexibility. Questions regarding funding and long-term implementation of both the Price Machine and/or SST remain unaddressed and should be in scope in this proceeding.

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[14] *Assigned Commissioner's Phase 1 Scoping Memo and Ruling*, R.22-07-005 (Nov. 2, 2022) (Demand Flexibility Scoping Ruling), at 5: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M498/K072/498072273.PDF.

[15] Demand Flex Staff Proposal.

[16] LMS Regulations, § 1632(c).

B. Consider Strategies to Reduce Barriers to DR Adoption Should be Added to the OIR Scope

The Commission should include in the scope of this proceeding consideration of how to reduce barriers to DR adoption. The OIR does not currently include an explicit consideration of ways to reduce barriers to DR adoption, including lowering barriers for entities to offer DR programs and for customers to participate in DR. In addition to data-related issues, other barriers to adoption may include, but are not limited to, customer information gaps, customer finances, and market barriers to DR providers. With diverse perspectives, parties to this proceeding can offer a variety of viewpoints on barriers to DR adoption, allowing the Commission to develop a foundational list of barriers to target and strategies to overcome them.

C. RTP Pilot Evaluations Should be in Scope to Incorporate Insights into Commission DR Policies

The Commission should amend the scope of this proceeding to consider results from RTP pilot evaluations as the Commission refines its DR policies. Preliminary Scoping Item 3 asks, "What standardized data systems, communication protocols, and data transfer processes should the Commission adopt or amend to support demand response initiatives, *including dynamic rates*?"[17] As the OIR indicates, this proceeding is meant to pick up an important topic from the Demand Flexibility proceeding related to systems and processes to implement dynamic rates, which D.25-08-049[18] (final decision in the Demand Flexibility proceeding) does not address. D.25-08-049 also does not stipulate a specific venue for discussing the results of the mid-term and final evaluations

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[17] OIR, at 9 (emphasis added).

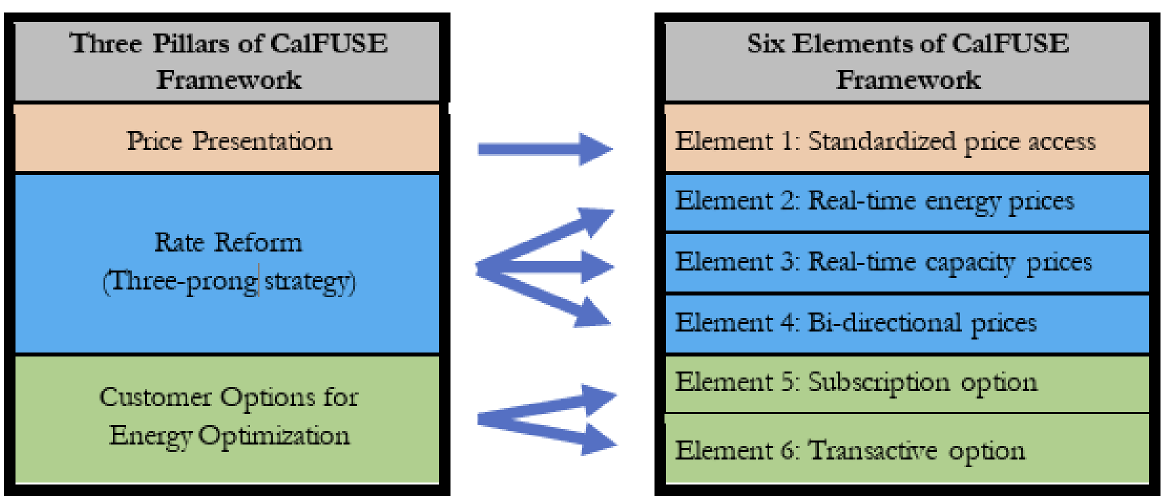
[1818] D.25-08-049, *Decision Adopting Guidelines for Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company on Demand Flexibility Rate Design Proposals*, R.22-07-005 (Aug. 28, 2025): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M578/K182/578182496.PDF.

of RTP pilots, which are set to conclude at the end of 2027.[19] The Commission plans to address dynamic rate-related systems and processes in this proceeding and because the review of the pilot evaluations will impact the needed systems and processes, this proceeding should include in scope an examination of both the mid-term and final evaluation results from the dynamic, RTP rate pilots. RTP pilot evaluations will provide valuable insights related not only to implementing real-time, dynamic rates but also to the future expectations of dynamic rates as part of California's DR landscape and the consideration of barriers to DR adoption described above. Therefore, the Commission should add to the scope of this proceeding consideration of RTP pilot evaluations.

D. The Demand Flex Staff Proposal Should be Revisited in this Proceeding

The Commission should revisit the Demand Flex Staff Proposal regarding advanced demand flexibility management and customer DER compensation, as discussed above. The Demand Flex Staff Proposal includes the CalFUSE policy roadmap, which contains six elements categorized under three pillars as shown in Figure 1.

Figure 1: Energy Division's CalFUSE Framework



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[19] D.24-01-032, *Decision to Expand System Reliability Pilots of Pacific Gas and Electric Company and Southern California Edison Company,* R.22-07-005 (Jan. 25, 2024), at 75 and 79, Conclusions of Law 2 and 19: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M524/K176/524176497.PDF.

As the Commission moves ahead in the instant proceeding, the elements of CalFUSE and other guiding principles in the Demand Flex Staff Proposal should be revisited to determine whether any updates or changes are necessary. More than three years have passed, and stakeholders now have more information from RTP pilots on dynamic rates for demand flexibility. Learnings from the development of LMS Compliance Plans can also inform potential adjustments to the Commission's vision for demand flexibility and customer compensation for DERs.

E. Enhanced Definitions of Demand Response, its Elements, and Types Should be Added to the Preliminary Scope

The Commission should define the DR landscape as it continues to expand. While the OIR lists topics for discussion in this proceeding, this OIR is an excellent venue for establishing a single, shared picture of the DR landscape for all stakeholders, including delineating between load modification and market-integrated demand response resources. A variety of DERs provide demand response and load shifting capabilities and this landscape is expanding to include things like dynamic rates. Dynamic rates are meant to incentivize load shifting in response to price signals. With different approaches to load flexibility and DR arising, it becomes more important to define and categorize them so that all stakeholders have the same understanding. For example, should dynamic rates be considered a DER or something else? What are the differences or similarities between how dynamic rates value DR compared to other DERs? Should different rules and valuation methodologies apply to different categories of DERs? Questions like these are important to consider for enhancing, valuing, and optimizing DR. Therefore, the Commission should include defining DR and its elements and types in the preliminary scope to ensure a shared understanding among stakeholders.

F. Cost-Effectiveness in the Context of DR Must be Defined to Satisfy DR Guiding Principles

The Commission should develop a reasonable definition of cost-effectiveness in the DR context to satisfy the Proposed DR Guiding Principle 3. Energy Division proposes updating guiding principles for DR, the third of which states:

> Demand response resources in California shall be cost-effective and demonstrate clear value by delivering measurable system and ratepayer benefits.[20]

However, no definition of cost-effectiveness accompanies this Proposed DR Guiding Principle.[21] Depending on the context, cost-effectiveness can be measured and applied in different ways, as can value. For example, the Total Resource Cost test is a common measure of cost-effectiveness for Commission-funded programs (*e.g.,* energy efficiency)[22], but the Commission also tracks cost-effectiveness metrics such as the Program Administrator Cost test and the Ratepayer Impact test.[23] The Commission often tracks avoided costs through the Avoided Cost Calculator, which measures the value associated with avoiding future costs, and total system benefits, which measure the grid benefits of reducing load through energy efficiency.[24] However, the measures

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20 *Guiding Principles for Demand Response in California*, R.25-09-004 (Sept. 9, 2025), at 9: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M582/K074/582074542.PDF.

21 Proposed DR Guiding Principle 3 states how resources should be determined to be cost-effective (*e.g.,* achieve measurable load shifting and reliably respond to price signals), but not what cost-effectiveness actually is.

22 *Energy Efficiency Policy Manual* (Apr. 2020), at Section 4.2: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/energy-efficiency/eepolicymanualrevised-march-20-2020-b.pdf.

23 *California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects* (Oct. 2001), at 13-25: https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpuc_public_website/content/utilities_and_industries/energy_-_electricity_and_natural_gas/cpuc-standard-practice-manual.pdf.

24 *CPUC Better Aligns Energy Efficiency Programs to Reduce GHG Emissions, Support Equity, and Increase Grid Stability,* R.13-11-005 (May 20, 2021): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M385/K242/385242131.PDF.

of cost-effectiveness and ratepayer value applied in the context of DR, including dynamic rates and load flexibility, are not yet defined.

Also unclear is whether a single definition of cost-effectiveness should apply to all types of DR considered in this proceeding. Since the Proposed DR Guiding Principle 3 requires cost-effectiveness for all DR in California, the definition(s) of cost-effectiveness will have a significant impact on the potential for various DR strategies to contribute to load flexibility. For this reason, the Commission should develop a definition, or multiple definitions, of cost-effectiveness for DR resources and strategies, as well as specify how to apply those definitions, in this proceeding.

III. THE COMMISSION SHOULD ADOPT THE DR GUIDING PRINCIPLES STAFF PROPOSAL WITH AMENDMENTS

A. The Commission Should Amend the DR Goal from D.16-09-056 to Include Customer Choice and Competitive Neutrality Among DR Providers

The Commission should update the goal for DR, originally adopted in D.16-09-056,[25] to include customer choice and competitive neutrality among DR providers. As stated in the Proposed DR Guiding Principles, the Commission formally adopted the goal for the future of DR programs:

> Commission regulated demand response programs shall assist the State in meeting its environmental objectives, cost-effectively meet the needs of the grid, and enable customers to meet their energy needs at a reduced cost.[26]

This goal, while robust, stands to benefit from the addition of two elements that are crucial to the success of DR in California: (1) customer choice; and (2) competitive neutrality. Not only are these two elements related in that competitive neutrality is essential to maximizing customer

25 D.16-09-056, at 97 and 98, O¶ 8.
26 Proposed DR Guiding Principles, at 5; D.16-09-056, at 97, O¶ 7.

choice among DR service providers, but they also increase the potential adoption of DR resources by customers. DR providers, including IOUs, CCAs, and third-party service providers, can offer resources and programs to customers better when they are all on an even playing field. Reducing barriers for DR providers and for customers will maximize the potential for DR load shifting. Additionally, the more options for customers, the more likely their needs will be met by a particular option. This increases the potential for DR to grow its contributions to California's load flexibility goals. In addition, more benefits are provided to customers whose ratepayer dollars are used to fund programs. CalCCA therefore recommends amending the DR Goal with the following underlined language:

> Commission regulated demand response programs shall assist the State in meeting its environmental objectives, cost-effectively meet the needs of the grid, <u>ensure competitive neutrality among demand response providers, and enable customers to choose the demand response provider</u> to meet their energy needs at a reduced cost.

B. DR Guiding Principle 3 Should Not Exclude Behavioral DR Programs and Resources from Being Considered Cost-Effective

Proposed DR Guiding Principle 3 should not exclude DR programs that rely on customers to take action to reduce or shift load from being considered cost-effective. As stated above, Proposed DR Guiding Principle 3 requires all DR in California to be cost-effective and to provide measurable benefits.[27] Energy Division states:

> A demand response resource that is not consistently available and doesn't reliably respond to the appropriate economic and reliability signals is not a cost-effective resource.[28]

This statement considers any DR resource or program that is not fully automated as not cost-effective, which is a non sequitur. It would be one thing to consider this statement in the context

[27] Proposed DR Guiding Principles, at 9.
[28] *Ibid.*

of CAISO market integration of DR and RA, where RA must be guaranteed. But determining that a resource is not cost-effective simply because it does not produce load reductions or shifts reliably does not follow.

While section 2.D. above discusses the lack of a *specific* definition of cost-effectiveness in the context of DR and load shifting, the *general* principle of cost-effectiveness is simply weighing costs against benefits. Proposed DR Guiding Principle 3 attempts to add other performance thresholds into that comparison, such as reliability or consistency. This is unreasonable. Though both reliability and consistency add value to DR, applying this description would eliminate two potential sources for load shifting. The first is DR programs that rely on customers to shift or reduce load based on text or email alerts. Just because a program with this structure does not achieve the same load shift or reduction every time an alert is sent out, does not mean the costs outweigh the benefits.

The second potential source of load shifting is dynamic rates. The description above considers dynamic rates not to be cost-effective, simply because the load shifting that the dynamic rates are designed to incentivize is dependent on customers changing their behavior in response to price signals.[29] While there are technologies and services that exist to respond to price signals automatically, customers may choose not to use them all or some of the time, depending on what their needs are. The Commission should not adopt this logic and exclude DR resources that rely on customer action to shift or reduce load because it would undermine

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[29] San Diego Gas & Electric Company (SDG&E) filed an Application for Rehearing (AfR) on September 29, 2025, in R.22-07-005, arguing that the dynamic rate guidance from D.25-08-049 is based on an insufficient record, insufficient procedural process, and fails to take into consideration the costs SDG&E will need to incur to implement D.25-08-049. SDG&E alleges D.25-08-049's requirements may make implementing dynamic rates non-cost-effective. Defining in the instant proceeding cost-effectiveness in different DR contexts will provide insight into SDG&E's AfR and whether SDG&E's methodology for weighing costs and benefits of dynamic rates conforms to those definitions.

California's load flexibility goals and customers' ability to save money from participating in DR programs or dynamic rates.

IV. THIS PROCEEDING SHOULD COORDINATE WITH OTHER CPUC RULEMAKINGS AND APPLICATIONS

The OIR asks, "Whether any specific issues previously addressed or underway in other Commission proceedings require coordination with this rulemaking."[30] CalCCA provides a list of proceedings, and the rationale recommended for coordination below.

Proceeding	Need for Coordination
R.25-04-010, Energy Efficiency	The Energy Efficiency proceeding has established cost-effectiveness protocols and integrated demand-side management valuation methodologies that should be considered.
R.22-11-013 Distributed Energy Resources	The DER proceeding is currently discussing cost-effectiveness issues and data access issues directly relevant to DR and dynamic rates.
R.21-06-017, High DER	The High DER proceeding is considering the value of DR within the distribution system.
R.25-08-004, Rule 21	The Rule 21 proceeding is considering distribution and interconnection issues related to distributed technologies related to reliability .
R.25-02-005, Power Charge Indifference Adjustment (PCIA)	The PCIA proceeding may consider potential changes to the valuation of resource adequacy (RA) in the PCIA to accommodate the implementation of the RA Slice of Day framework.
R.25-10-003, Resource Adequacy (RA)	The RA proceeding is considering program reforms and refinements, which may affect RA SOD and CAISO market integration for RA.

30 OIR, at 10.

Proceeding	Need for Coordination
A.24-10-014, PG&E Billing Modernization	PG&E's Billing Modernization Application proposes significant system updates relevant to data systems, preliminarily scoped into the instant proceeding.
A.24-09-014, PG&E General Rate Case, Phase II	In compliance with D.25-08-049, PG&E is presenting RTP rate design and implementation as well as a proposal to create a "Stop-Gap" RTP pilot extension.[31]
CAISO Demand and Distributed Energy Market Integration (DDEMI)	CAISO's DDEMI initiative is considering market integration for DR and DERs.

V. RECOMMENDED SCOPE PRIORITIZATION AND CLARIFICATIONS

A. The Forthcoming DR Scoping Ruling Should Estimate Dates for Future Staff Proposals for Each Preliminary Scoping Item

CalCCA agrees with the preliminary schedule for this proceeding. However, the Commission should provide estimated dates for any future Energy Division staff proposals for preliminary scoping items in the forthcoming DR Scoping Memo and Ruling. This proceeding is taking on a large number of issues. The sooner dates are set from which to work, the better all stakeholders can plan to engage, including Energy Division staff developing proposals. Additionally, as discussed in section IV. above, understanding the Commission's full vision for this proceeding is helpful for stakeholders when proposals and decisions in this proceeding may impact outcomes in other proceedings, or vice versa.

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[31] PG&E presents its "Stop-Gap" RTP Pilot proposal in its *Motion of Pacific Gas and Electric Company (PG&E) to Adopt a Schedule for the Bifurcated Real-Time Pricing Track of PG&E's General Rate Case Phase II*, A.24-09-014 (Nov. 6, 2025), at 2: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M586/K273/586273785.PDF.

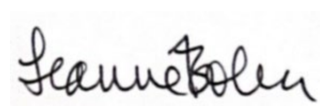
B. The Commission Should Consider Adding a Separate Ratesetting Track to Consider Funding of Commission and CEC RTP or LMS Data Systems

CalCCA agrees with the categorization of this proceeding as quasi-legislative. However, the Commission should consider adding a ratesetting track to consider funding for Commission and CEC required data systems for RTP and LMS. The Commission is well-positioned to clarify cost recovery of data systems supporting DR and dynamic rates in this proceeding. While many DR programs will have their costs approved in individual IOU applications, the statewide nature of some of elements, such as the Price Machine and/or SST, could impact IOUs and CCAs collectively. For these reasons, the Commission should consider adding a separate ratesetting track to determine reasonable cost recovery for RTP and LMS-related initiatives if necessary.

VI. CONCLUSION

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

Respectfully submitted,



Leanne Bober,
Director of Regulatory Affairs and Deputy General Counsel

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

November 13, 2025

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	R.25-10-003

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON THE ORDER INSTITUTING RULEMAKING

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

November 14, 2025

TABLE OF CONTENTS

SUMMARY OF RECOMMENDATIONS[1]

The Commission should:

- Modify the schedule to allow for party review of LOLE I&As and study results, as recommended by Cal Advocates and SCE;
- Modify the scope of this proceeding to include DR exports, as recommended by CALSSA and PG&E;
- Address a newly created gap with the LCR-RCM calculation identified through PG&E's Opening Comments; and
- Reject TURN's recommendation for a GHG-emissions attribution to the resources LSEs can contract with to meet RA obligations.

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

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

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	R.25-10-003

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY
COMMENTS ON THE ORDER INSTITUTING RULEMAKING**

The California Community Choice Association[2] (CalCCA) submits these comments pursuant to Rule 6.2 of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure,[3] in response to the *Order Instituting Rulemaking*[4] (OIR), issued October 15, 2025, and the directives therein.

I. INTRODUCTION

Party Opening Comments,[5] including CalCCA's Opening Comments, demonstrate general support for the preliminary scope set forth in the OIR, with some modifications. These

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

[4] *Order Instituting Rulemaking*, Rulemaking (R.) 25-10-003 (Oct. 15, 2025): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M583/K934/583934825.PDF.

[5] All references herein to party Opening Comments are to the Opening Comments filed in this Rulemaking, R.25-10-003, on or about November 4, 2025.

Reply Comments respond to four recommendations from Party Opening Comments. *First*, the Commission should adopt recommendations from the Public Advocates Office at the California Public Utilities Commission (Cal Advocates) and Southern California Edison Company (SCE) to modify the schedule to include a process for reviewing the loss of load expectation (LOLE) study inputs and assumptions (I&A) and study results with parties.[6] The LOLE study used to set the planning reserve margin (PRM) is a complex process that has significant impacts on resource adequacy (RA) costs and system reliability. It is therefore necessary for parties to have adequate opportunities to provide input into the study methodology and to review the results.

Second, the Commission should modify the scope of this proceeding to include a review of RA rules related to behind-the-meter (BTM) resources with the ability to export, as recommended by California Solar and Storage Association (CALSSA) and Pacific Gas and Electric Company (PG&E).[7] The California Independent System Operator (CAISO) is in the process of considering enhancements to its market rules related to BTM exports within its Demand and Distributed Energy Market Integration (DDEMI) stakeholder initiative. The Commission should simultaneously develop the necessary rules within its jurisdiction, including a qualifying capacity methodology, for BTM exports to provide RA capacity.

Third, the Commission should clarify the methodology for calculating the Local Capacity Requirement Reduction Compensation Mechanism (LCR-RCM) in response to PG&E's Opening Comments to address a new data gap that may prevent the Commission from using its adopted methodology for calculating the local RA premium used for the LCR-RCM.[8] While PG&E's recommendation to align the LCR-RCM calculation with the Power Charge

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6 *See* Cal Advocates Opening Comments, at 1-3; SCE Opening Comments, at 3-8.
7 *See* CALSSA Opening Comments, at 2; PG&E Opening Comments, at 7-8.
8 *See* PG&E Opening Comments, at 3-4.

Indifference Adjustment (PCIA) RA Market Price Benchmark (MPB) methodology may be reasonable, it raises a potential new data gap that must be addressed to clarify how the Commission will calculate the LCR-RCM.[9]

Fourth, the Commission should reject The Utility Reform Network's (TURN) recommendation to assign "a share of [greenhouse gas (GHG)] emissions attributable to the reliability resources for which [LSEs] contract to meet RA obligations."[10] The Commission should instead address reliability, and clean energy needs comprehensively within the Reliable and Clean Power Procurement Program (RCPPP) and allow load-serving entities (LSE) to optimize across compliance obligations to minimize costs.

As set forth below, CalCCA respectfully recommends the Commission:

- Modify the schedule to allow for party review of LOLE I&As and study results, as recommended by Cal Advocates and SCE;
- Modify the scope of this proceeding to include demand response (DR) exports, as recommended by CALSSA and PG&E;
- Address a newly created gap with the LCR-RCM calculation identified through PG&E's Opening Comments; and
- Reject TURN's recommendation for a GHG-emissions attribution to the resources LSEs can contract with to meet RA obligations.

II. A PROCESS SHOULD BE ESTABLISHED TO REVIEW THE LOLE I&AS AND STUDY RESULTS WITH PARTIES AS RECOMMENDED BY CAL ADVOCATES AND SCE

The Commission should adopt recommendations from Cal Advocates and SCE to modify the schedule to include a process for reviewing the LOLE I&As and study results with parties. The OIR includes a LOLE study in the scope of this proceeding, in which the

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9 *See* PG&E Opening Comments, at 3-4.

10 TURN Opening Comments, at 2.

Commission will consider modifications to the PRM for 2028 and 2029.[11] CalCCA supports including this item in scope and shares the concerns of Cal Advocates and SCE that the OIR does not include a process for reviewing the I&As and results with parties.[12]

Cal Advocates emphasizes the importance of the LOLE study, stating:

> The LOLE study informs the RA [PRM] and is likely the most consequential single source of information in the rulemaking, both in terms of ratepayer cost for RA procurement to meet the PRM and for ensuring system reliability. Consequently, stakeholder input on this study is extremely important.[13]

Given the significant impact the LOLE study has on ratepayer affordability and system reliability, it is critically important for parties to have adequate opportunity to provide input into the development of the study and to thoroughly review the results. As stated by SCE:

> "[t]o ensure the Commission and parties have enough time to engage in a robust stakeholder process for the complex work being done to develop a PRM in the new [SOD] framework, the Commission should provide parties and Energy Division with a schedule that clearly identifies responsibilities and tasks and the time which parties and Energy Division have to perform them.[14]

The Commission should therefore adopt the recommendations from Cal Advocates and SCE to include a process for reviewing the LOLE I&As and study results with parties.

III. DR EXPORTS SHOULD BE ADDRESSED IN THIS PROCEEDING, AS RECOMMENDED BY CALSSA AND PG&E

The Commission should modify the scope of this proceeding to include a review of RA rules related to BTM resources with the ability to export, as recommended by CALSSA and PG&E.[15] As stated by PG&E,

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[11] *See* OIR, at 4.
[12] *See* Cal Advocates Opening Comments, at 1-3; SCE Opening Comments, at 3-8.
[13] Cal Advocates Opening Comments, at 2.
[14] SCE Opening Comments, at 4.
[15] *See* CALSSA Opening Comments, at 2; PG&E Opening Comments, at 7-8.

> [p]reviously, the Commission noted in D.20-06-031 that BTM resources may continue to participate in the RA program as DR resources; however, the load impact from energy storage in a DR program can only be recognized up to the entirety of the delivered load. In other words, the DR load impact does not count any net export from a battery. This presents a barrier to scaling BTM storage in California.[16]

CalCCA agrees with CALSSA and PG&E that, in developing a qualifying capacity methodology for BTM exports, there are several key questions that must be addressed in coordination with the California Energy Commission and the CAISO.[17] This proceeding and the recently opened Demand Response OIR (R.25-09-004)[18] should address these questions in alignment with the CAISO's efforts to develop a market model and establish a deliverability assessment methodology. In the CAISO's ongoing DDEMI stakeholder initiative, the CAISO is considering a modified Proxy Demand Resource model to improve the ability of BTM resources to participate in wholesale markets by crediting net exports and revising metering requirements.[19] As the CAISO develops its market rules related to BTM exports, the Commission should simultaneously develop the necessary rules within its jurisdiction, including a qualifying capacity methodology, for BTM exports.

IV. PG&E'S OPENING COMMENTS IDENTIFY A NEWLY CREATED GAP WITH THE LCR-RCM CALCULATION

The Commission should clarify the methodology for calculating the LCR-RCM to address a new data gap identified in PG&E's Opening Comments.[20] The current LCR-RCM

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16 PG&E Opening Comments, at 7 (footnote omitted).

17 CALSSA Opening Comments, at 2; PG&E Opening Comments, at 7-8.

18 *Order Instituting Rulemaking to Enhance Demand Response in California,* R.25-09-004 (Sept. 9, 2025): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M582/K072/582072320.PDF.

19 Sunrun, Tesla, & CALSSA, *Behind-the-Meter Storage Participation in Wholesale Markets,* CAISO DDEMI Working Group (Sept. 9, 2025): https://stakeholdercenter.caiso.com/InitiativeDocuments/CalSSA-Sunrun-Tesla-Presentation-Demand-Distributed-Energy-Market-Integration-Sep-09-2025.pdf.

20 PGE& Opening Comments, at 3-4.

calculation uses the same weighted average prices used to set the PCIA RA MPB to determine local RA premiums.[21] PG&E requests the Commission consider whether the data set used to calculate the LCR-RCM price should align with the revised methodology and data set for the system RA MPB used in establishing the PCIA rate. D.25-06-049 modifies the data set used to calculate the PCIA RA MPB in several ways, including expanding the transaction window and removing affiliate, swap, and sleeve transactions.[22] PG&E asks the Commission to consider whether to apply the same modifications to the calculation of the LCR-RCM.

While PG&E's recommendation to align the LCR-RCM calculation with the PCIA RA MPB methodology may be reasonable, it raises a potential new data gap that must be addressed to clarify how the Commission will calculate the LCR-RCM. In modifying the calculation methodology for the PCIA RA MPB, D.25-06-049 also adopts a single MPB value rather than "artificially dividing the market into system, flexible and local MPB values."[23] Given this new modification to the dataset, it is unclear how the Commission will calculate the local RA premium for the LCR-RCM.

V. TURN'S RECOMMENDATION FOR A GHG-EMISSIONS ATTRIBUTION SHOULD BE REJECTED

The Commission should reject TURN's recommendation to assign "a share of GHG emissions attributable to the reliability resources for which [LSEs] contract to meet RA obligations."[24] TURN conflates a capacity attribute (RA) and an energy attribute (RPS/clean energy). While the RA construct has moved to an hourly measure, it still represents each hour in

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[21] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/lcr-rcm-2025.pdf.

[22] D.25-06-049, *Decision Adopting Changes to the Calculation of the Resource Adequacy Market Price Benchmark*, R.25-02-005 (June 26, 2025): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M571/K242/571242473.PDF.

[23] *Id.* at 20.

[24] TURN Opening Comments, at 2.

the month as the "worst day." This means that the RA construct imagines that the highest load can happen in any day of the month and that LSEs must procure capacity to meet that need at any day of the month. However, the worst day will not occur every day and therefore not all of the capacity procured will be needed for energy during the month. It is entirely possible that a procured RA capacity resource will never operate during the month if not needed and cost justified in the CAISO market. Further, if the resource does operate, it is not necessarily operated to serve the load of the LSE that procured it as RA.

The Commission should reject TURN's recommendation for the following reasons. *First*, the Commission is currently considering how to address GHG-emissions reduction and reliability within the RCPPP. The Commission should develop a comprehensive program that addresses reliability and clean energy within RCPPP rather than adding additional requirements that may constrain the capacity LSEs can procure to meet its RA obligations.

Second, CalCCA disagrees with TURN's statement that, "[a]bsent any GHG attribution, LSEs would have zero incentive to minimize reliance on fossil generation to meet reliability obligations"[25] LSEs are incentivized to procure low and zero-GHG resources to optimize across RA, RPS, and IRP requirements to ensure compliance across all programs while minimizing costs. Introducing another constraint to LSE RA procurement could result in increased costs. LSEs should have the ability to meet compliance obligations – both reliability and GHG-emissions reductions obligations – in the most cost-effective manner. This type of procurement is based upon not only peak capacity needs but also energy needs over the entire period. The RA structure imagines that the peak need occurs in all days of the month which would

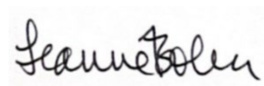
[25] TURN Opening Comments, at 2.

dramatically overstate energy needs if using the TURN proposal. The Commission should therefore not adopt a GHG-emissions attribution element to the RA program.

VI. CONCLUSION

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

Respectfully submitted,



Leanne Bober,
Director of Regulatory Affairs and Deputy General Counsel

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

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

Order Instituting Rulemaking to Consider New Approaches to Disconnections and Reconnections to Improve Energy Access and Contain Costs.	R.18-07-005

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING COMMENTS ON E-MAIL RULING ON ARREARAGE-RELATED ASSISTANCE PROGRAMS

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

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

November 14, 2025

TABLE OF CONTENTS

SUMMARY OF RECOMMENDATIONS[1]

CalCCA recommends the Commission take the following actions based on the PIPP and AMP final evaluations.

✓ Establish PIPP as a permanent program, with the following parameters:

- Undertake an additional evaluation of PIPP after the four-year implementation period concludes in 2026;
- Continue allowing customers to participate at the current energy burden thresholds;
- Coordinate across programs such as the CARE, PIPP, and AMP to provide bill payment assistance and arrearage forgiveness to customers, rather than overhauling the CARE program;
- Reject the recommendation to require high-energy usage customers in PIPP to participate in the ESA program unless more data are provided to warrant doing so;

✓ Establish AMP as a permanent program, with the following parameters:

- Reject the recommendation to require customers to complete CARE post-enrollment verification before AMP enrollment;
- Modify the proposed time range for customers to have made a bill payment from 24 months to 12 months for eligibility in AMP, rather than to six months;
- Continue disconnection protections for AMP participants by allowing: (1) partial payments to count towards valid program payments; and (2) valid program payments to offset missed payments before disenrolling customers;
- Require IOUs to communicate with customers prior to removing them from AMP, including informing customers of a local CBO they can reach out to for bill assistance;
- Reject the recommendation to adopt a five-year stay-out provision after completing AMP;
- Require IOUs to provide on-bill or online their AMP participation metrics, including the original AMP arrearage, the amount forgiven each month, the amount forgiven to date, and the amount remaining;

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

Summary of Recommendations continued

- Require IOUs to remind AMP participants one week before the bill due date about the upcoming due date via the customer's desired communication methods; and

- Reject the recommendation to allow IOUs to disconnect customers while in the AMP program, and to rely on individual IOU disconnection thresholds for disconnections while customers are still in AMP.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Consider New Approaches to Disconnections and Reconnections to Improve Energy Access and Contain Costs.	R.18-07-005

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING COMMENTS ON E-MAIL RULING ON ARREARAGE-RELATED ASSISTANCE PROGRAMS

California Community Choice Association[2] (CalCCA) submits these opening comments pursuant to the *E-Mail Ruling on Arrearage Related Assistance Programs*[3] (Ruling), dated October 13, 2025, and to the *Email Ruling Modifying CBO-Related Questions and Extending Comment Deadline*, dated October 21, 2025.[4] The Ruling provides parties the opportunity to comment on a procedural path forward for three of the California Public Utilities Commission's (Commission) programs that were developed to assist customers in forgiving or paying down their past-due balances: the Arrearage Management Payment Plan (AMP), the Community Based Organization (CBO) Arrears Case Management Pilot Program (CBO Pilot), and the Percentage of Income Payment Plan (PIPP) pilot.

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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 *E-Mail Ruling on Arrearage Related Assistance Programs*, Rulemaking (R.) 18-07-005 (Oct. 13, 2025): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M583/K960/583960513.PDF.

4 *Email Ruling Modifying CBO-Related Questions and Extending Comment Deadline*, R.18-07-005 (Oct. 21, 2025) (CBO Ruling): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M584/K626/584626082.PDF.

I. INTRODUCTION

The combined customer arrears of the three large investor-owned utilities (IOU) were over $1.6 billion as of the latest reports from the IOUs, which include arrears for community choice aggregator (CCA) customers.[5] This is a staggering number, and while the total has decreased from over $1.8 billion reported in January 2025,[6] the need for effective bill assistance and disconnection protections remains high. The Commission is considering recommendations from final evaluations for the PIPP and AMP[7] and has the opportunity to continue the customer assistance provided by these pilots. A portion of CCAs have been participating in one or both of the pilots for PIPP and AMP and all customers, bundled or unbundled, stand to benefit from the continuation of the customer assistance they offer.

PIPP and AMP take complementary approaches to helping customers reduce their energy burden. PIPP *caps bills* for participating customers based on their income level, thereby limiting overall monthly energy burden. AMP provides the opportunity for customers to receive *arrearage forgiveness* while practicing consistent bill payment. Evaluations for these programs demonstrate that they have achieved their primary goals of reducing energy burden and decreasing customer arrearages. CalCCA supports the continued implementation of both PIPP

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5 *Pacific Gas and Electric Company's (U 39M) Monthly Disconnection Data Report,* R.18-07-005 (Oct. 20, 2025) (PG&E Data Report), at Attachment A: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M584/K630/584630718.PDF; *see also Southern California Edison Company's (U 338-E) Monthly Disconnect Data Report September 2025*, R.18-07-005 (Oct. 20, 2025) (SCE Data Report): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M584/K630/584630717.PDF, at A-6; *see also Disconnection Settlement Monthly Report of San Diego Gas & Electric Company (U 902 M)*, R.18-07-005 (October 20, 2025) (SDG&E Data Report): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M583/K961/583961267.PDF, at Attachment A, Section 3.

6 *Ibid*.

7 Administrative Law Judge Dugowson clarified via the CBO Ruling that the informal CBO Pilot recommendations have not yet been published.

and AMP as recommended by the final evaluations of these programs. These comments respond to the Ruling questions, and provides feedback on specific recommendations.

For the reasons set forth below, CalCCA recommends the Commission:

- ✓ Establish PIPP as a permanent program, with the following parameters:
    - Undertake an additional evaluation of PIPP after the four-year implementation period concludes in 2026;
    - Continue allowing customers to participate at the current energy burden thresholds;
    - Coordinate across programs such as the California Alternative Rate for Energy (CARE), PIPP, and AMP to provide bill payment assistance and arrearage forgiveness to customers, rather than overhauling the CARE program;
    - Reject the recommendation to require high-energy usage customers in PIPP to participate in the Energy Savings Assistance (ESA) program unless more data are provided to warrant doing so;
- ✓ Establish AMP as a permanent program, with the following parameters:
    - Reject the recommendation to require customers to complete CARE post-enrollment verification before AMP enrollment;
    - Modify the proposed time range for customers to have made a bill payment from 24 months to 12 months for eligibility in AMP, rather than to six months;
    - Continue disconnection protections for AMP participants by allowing: (1) partial payments to count towards valid program payments; and (2) valid program payments to offset missed payments before disenrolling customers;
    - Require IOUs to communicate with customers prior to removing them from AMP, including informing customers of a local CBO they can reach out to for bill assistance;
    - Reject the recommendation to adopt a five-year stay-out provision after completing AMP;
    - Require IOUs to provide on-bill or online their AMP participation metrics, including the original AMP arrearage, the amount forgiven each month, the amount forgiven to date, and the amount remaining;

- Require IOUs to remind AMP participants one week before the bill due date about the upcoming due date via the customer's desired communication methods; and

- Reject the recommendation to allow IOUs to disconnect customers while in the AMP program, and to rely on individual IOU disconnection thresholds for disconnections while customers are still in AMP.

II. CALCCA'S RESPONSES TO QUESTIONS POSED IN THE RULING

A. Procedural Path Forward for PIPP Pilot

1. Which recommendations from the PIPP evaluation report should the Commission adopt, if any, and why?

The PIPP Evaluation provides three categories of recommendations: (1) pilot recommendations; (2) short-term recommendations following the pilot; and (3) long-term recommendations following the pilot.[8] CalCCA responds to the recommendations from each category below.

a. The First PIPP Pilot Recommendation that the IOUs Communicate with Customers Regarding Additional Assistance Programs Should be Adopted

CalCCA supports the first PIPP recommendation that the IOUs communicate with customers on the PIPP regarding additional available assistance programs. The PIPP evaluation recommends that the IOUs:

> Reach out to Pilot participants who have high levels of arrearages (over $200) and inform them of available programs that they may benefit from including [Low Income Home Energy Assistance Program], AMP, and the [Energy Savings Assistance] Program. This could potentially lead to achievement of a Pilot goal that was not attained, which was to increase participation in assistance programs.[9]

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[8] *Percentage of Income Payment Plan Pilot Program Final Evaluation Report* (PIPP Evaluation), R.18-07-005 (Mar. 17, 2025), Attachment A, at ix-xi: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M559/K072/559072952.PDF.

[9] *Id.*, Attachment A, at x.

Customer outreach and education are foundational to ensuring customers understand their bills, as well as changes to energy policy that affect their bills and ways they can save money. This is especially true for low-income assistance programs such as PIPP. If the IOUs have not already done so, the Commission should require the IOUs to implement this recommendation to enhance customer awareness of assistance programs.

b. The PIPP Evaluation's Recommendation to Require an Additional Evaluation to Inform Longer-Term Impacts Should be Adopted

The Commission should adopt the second recommendation from the PIPP Evaluation that an additional evaluation be performed after the implementation period concludes in 2026 to inform longer-term impacts of participation.[10] This additional evaluation will ensure a complete understanding of how elements of implementing the pilot achieved pilot goals and can inform a future, permanent implementation of PIPP.

c. The Commission Should Reject the PIPP Evaluation's Recommendation to Auto-enroll all CARE Customers in the PIPP Program for the Purpose of Lowering Program Costs

The Commission should reject the PIPP Evaluation's recommendation to auto-enroll all CARE customers in the PIPP program for the purpose of lowering program costs. The PIPP Evaluation's post-pilot, short-term recommendation is to limit the eligibility for a permanent program to CARE customers with higher energy burdens, specifically to increase the electric energy burden target from 3 percent to 4.5 percent.[11] The rationale of lowering program costs is reasonable and is accompanied by an estimated annual cost savings of approximately $230 million. Adopting this recommendation would decrease a non-participating, non-CARE

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[10] *Ibid.*

[11] *Id.* at x.

customer's annual bill from $59 to $41, for an annual savings of $18.[12] While this estimate does provide cost savings overall, it assumes that PIPP will become an opt-out program that *auto-enrolls* all CARE customers. If the Commission implements a more permanent version of PIPP, however, it should not auto-enroll all CARE customers but rather only enroll those who sign up to participate. This approach would reduce program costs compared to the estimates in the PIPP Evaluation, but provide subsidies to only those who request them to ensure they are used intentionally and efficiently. For this reason, CalCCA does not support the PIPP Evaluation's recommendation to enroll only high-energy burden CARE customers.

d. The Only Long-Term, Post-Pilot Recommendation that Should be Adopted is to Combine Bill Payment Assistance and Arrearage Forgiveness into a Single Program

The PIPP Evaluation makes three longer-term recommendations to implement after the pilot has concluded. As set forth below, CalCCA recommends adopting the recommendation to combine bill payment assistance and arrearage forgiveness into a single program. CalCCA recommends rejecting the two other recommendations to: (1) overhaul the CARE program to incorporate PIPP which would be overly complicated and unnecessary; and (2) replace PIPP credit discount caps with a new policy to require participation in ESA for high-usage, high-subsidy customers in the PIPP program, because the PIPP Evaluation did not find that participating customers too advantage of the PIPP benefits to increase their energy usage, but rather simply used the program to meet their basic needs.

[12] *Id*. at 66, Table IV-19 and 67, Table IV-22 (the difference between the total cost without information technology (IT) of participation in PIPP of all CARE customers across utilities of $749,876,516 and the cost of only high energy burden CARE customers of $519,765,862 is $230,110,654); *see also id.* at 68, Table IV-23 (the difference between the estimated per-customer cost of subsidizing all CARE customers of $59 and of subsidizing only high burden CARE customers of $41 is $18).

The Commission should reject the first proposal to develop "one low-income energy bill payment assistance program that improves targeting of assistance to those customers with unaffordable energy bills."[13] Despite the conceptual merits of this recommendation, CalCCA opposes it on the grounds that such an undertaking would be overly complicated, has unknown costs, and would require extensive resources from numerous stakeholders, including IOUs, CCAs, consumer advocates, and the Commission. The PIPP Evaluation explains that CARE and PIPP would get replaced with a single program that "determines the customer's monthly payment based on the household's verified income level and a targeted energy burden level."[14] Replacing CARE and PIPP constitutes an overhaul of both programs and verifying customer income beyond the self-attestation that programs like CARE utilize is still uncertain for the Base Services Charge (BSC) (formerly known as the income-graduated fixed charge). The BSC Process Working Group, initiated by D.24-05-028, has been working to determine practical methods for verifying customer incomes on a large scale.[15] The Working Group Report from the BSC Process Working Group has not yet been submitted, nor has the Commission issued a proposed decision on income verification methodologies to the extent envisioned in this recommendation.

Instead, the Commission should adopt the second long-term recommendation from the PIPP Evaluation, which is to develop a joint program that provides both bill payment assistance and arrearage forgiveness.[16] Developing a joint program does not require the overhauling of the well-established CARE program on which millions of Californians rely. This joint program

[13] *Id.* at xi.

[14] *Ibid.*

[15] D.24-05-028, *Decision Addressing Assembly Bill 205 Requirements for Electric Utilities*, R.22-07-005 (May 9, 2024), at 148, Conclusion of Law 14 (stating the reasonableness of establishing a Process Working Group to develop a proposal that proposes income verification processes and alternatives and cost-benefit analysis of income verification processes): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M531/K686/531686019.PDF.

[16] *Ibid*.

could build off the existing infrastructure from implementing PIPP and AMP such that the activities between the two programs can be coordinated and tracked. The important piece as identified by the PIPP Evaluation, is to ensure customers have access to *both* types of assistance:

> While payment assistance through programs such as CARE and PIPP make the current bill affordable, the bill may become unaffordable if the customer's payment plan for past arrearages requires an additional payment. While an arrearage forgiveness program eliminates past debt, additional debt will be accumulated if the current bill is not affordable. For these reasons, customers need both types of energy assistance programs.[17]

This demonstrates the complementary nature of decreasing low-income customer bills through PIPP *and* allowing them to tackle their arrearages through AMP. For this reason, the Commission should adopt the recommendation to develop a joint program that provides bill assistance and opportunities for arrearage forgiveness.

In addition, the Commission should reject the third long-term, post-pilot implementation recommendation to replace PIPP credit discount caps with a new policy to require participation in ESA for high-usage, high-subsidy customers in the program in order to control program costs.[18] The PIPP Evaluation includes concerns that customers in PIPP are incentivized to use more energy because their bills are capped.[19] However, the Evaluation found that respondents to the customer survey reported that they were simply better able to meet their needs after enrolling in PIPP.[20] While CalCCA appreciates concerns of keeping program costs low, the PIPP Evaluation does not present sufficient evidence that customers used more energy as a result of their bills being capped. On the other hand, the PIPP Evaluation does include evidence that

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17 *Ibid*.

18 *Ibid.* High usage is defined as 600 percent of baseline usage by Pub. Util. Code section 739.1(j)(2) in the context of the CARE program.

19 *Id.* at 75 (programs of any kind with energy bill caps create concerns that participants will increase their energy usage).

20 *Ibid*.

customers are using PIPP to simply meet their needs rather than inappropriately taking advantage of the program. Therefore, the Commission should not adopt this recommendation without further evidence that the PIPP program was used for anything other than customers meeting their basic energy needs.

2. Should the Commission terminate the PIPP pilot before its scheduled sunset date? Why or why not?

No. The Commission should follow the recommendations of the PIPP Evaluation by continuing the Pilot through its original implementation period. This will allow data collection through the full, planned term of implementation and continue to provide the benefits to customers who rely on the pilot for reducing energy burden.

3. Should the Commission consider any other modifications to the PIPP pilot?

CalCCA does not have additional recommended modifications at this time.

B. Procedural Path Forward for AMP

1. Should the Commission allow the AMP to continue until its scheduled sunset date? Why or why not?

The Commission should allow AMP to continue until its scheduled sunset date because it has proven to reduce arrearages for low-income customers. According to the most recent Monthly Disconnection Data Reports, total arrearages across the IOUs remain high, at over $1.6 billion as of September 2025.[21] Reducing arrearages benefits more than just those who pay off balances or have their past-due amounts forgiven. Reductions to total arrearages also lower costs for all ratepayers, as all customers must pay for some amount of revenue requirement that was undercollected from customers with past-due balances.

[21] PG&E Data Report, at Attachment A; *see also* SCE Data Report, at A-6; *see also* SDG&E Data Report, at Attachment A, Section 3.

2. Which of the recommendations in the AMP evaluation report should the Commission adopt, and which recommendations should the Commission reject? Why?

The AMP Evaluation makes nine recommendations.[22] CalCCA responds to each recommendation below.

a. The Commission Should Continue AMP as a Permanent Program, With Modifications

CalCCA supports the recommendation to continue AMP as a permanent program, with some modifications. The AMP Evaluation found that AMP has achieved its program goal of reducing arrearages for participants who successfully completed the program, ranging on average from $537 to $876, depending on the program cohort.[23] Since the program has met its goal and provides meaningful reductions to arrearages to customers who require assistance, the Commission should continue to implement AMP which will support overall arrearage reductions.

b. The Recommendation that Customers Complete CARE Post-enrollment Verification Prior to Enrolling in AMP Should be Rejected

The Commission should not adopt Recommendation 2 which would require CARE post-enrollment verification prior to a customer being enrolled in AMP. Customers currently self-certify their eligibility for CARE or Family Electric Rate Assistance (FERA) when enrolling in AMP. The apparent concern from the AMP Evaluation is that customers applying to AMP will self-certify that they are eligible for CARE or FERA when they are actually ineligible.[24] First, the AMP Evaluation does not provide quantitative evidence on how many customers were found to be ineligible and remained in the program. The concern reflected in the AMP Evaluation stems

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22 *Arrearage Management Plan Final Evaluation Report* (AMP Evaluation) (Oct. 1, 2025), at 102-104.

23 *Id*. at 98 (presenting key findings related to arrearage forgiveness).

24 *Id*. at 103 (describing the rationale for Recommendation 2 that customers should be required to enroll in CARE or FERA prior to being enrolled in AMP).

from a survey given to IOU staff,[25] which is anecdotal rather than quantitative. Second, CARE and FERA are themselves programs for which customers self-certify their income to enroll. If a customer ineligible for CARE or FERA is determined to enroll in AMP, they may also falsely enroll in CARE or FERA under this recommendation's process. While CalCCA supports the efficient use of program funds, there is insufficient evidence to warrant increasing the administrative burden and slowing customer enrollment by adding extra steps to the enrollment process. The Commission should not adopt this recommendation from the AMP Evaluation.

c. The Commission Should Reject the Recommendation to Shorten the Timeframe of a Customer's Prior Bill Payment to Within Six Months for AMP Eligibility

The Commission should reject the AMP Evaluation's recommendation to shorten the length of time for which a customer enrolling to AMP must have made one bill payment to six months from 24 months prior to enrollment. Currently, customers must have made a bill payment in the 24 months leading up to enrolling in AMP. As set forth below, if the Commission chooses to shorten the timeframe, it should reduce it to 12 months only to account for the affordability crisis currently being experienced by ratepayers. Additionally, the Commission should consider allowing partial bill payments to count towards past payments for AMP eligibility, as this demonstrates customer commitment to paying energy bills.

Customers are struggling with electric bills, as is evidenced by the massive amount still in arrears statewide. Shortening the length of time in which a customer must have made a bill payment to six months is an extreme shift for which the AMP Evaluation does not support with quantitative evidence. Again, this recommendation is made based on anecdotal IOU staff survey

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25 *Id*. at 11 (describing IOU staff recommendations to address concerns related to AMP eligibility).

results[26] and a subjective determination that a 24-month window "does not show a commitment or ability to pay the energy bill, which is needed for the customer to be successful on AMP."[27] This logic is reasonable, but without quantitative evidence to rationalize such an eligibility shift, the Commission should err on the side of caution by selecting the more conservative modification of using a 12-month window instead of a six-month window, especially when arrears are still so high. Additionally, the Commission should consider allowing partial bill payments to count towards past payments for AMP eligibility, as this demonstrates customer commitment to paying energy bills.

d. The Recommendation to Replace the AMP Disenrollment with the IOU Disconnection Policies Should be Rejected and Instead Alternative Policies Should Be Adopted to Support Customer AMP Success

The Commission should reject the AMP Evaluation's recommendation to replace the AMP disenrollment policies with the IOU Disconnection policies. Instead, alternative policies should be adopted to provide more leniency to customers in AMP before disenrolling them. Currently, AMP removes customers from the program when they miss two consecutive payments (or make them late or less than in full) or three non-consecutive payments during their participation. The AMP Evaluation recommends that this disenrollment criterion be removed and instead, replaced with the policy that if a customer's arrearage balance goes beyond their IOU's disconnection threshold, the IOU should disconnect the customer and then remove the customer from AMP.[28] Providing more leniency to customers making partial payments in good faith and/or those struggling to pay other bills will provide more opportunities for them to successfully

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[26] *Ibid.* (listing the IOU staff recommendation to reduce the window for past payments from 24 months to six months or 12 months).

[27] *Id.* at 103.

[28] *Ibid.* (listing the third modification that the IOUs should implement as soon as possible).

get their arrearages forgiven by AMP. However, immediately disconnecting customers who become past due will remove the current disconnection protections that program participants rely on. This recommendation replaces a customer accountability measure (an incentive not to miss payments for fear of being removed from AMP) with a more extreme one. Rather than being removed from AMP and restarting the "disconnection timer," customers are at risk of accelerating this and getting disconnected while participating in AMP. Additionally, relying on individual IOU disconnection thresholds and discretion creates an equity problem in which AMP participants are treated differently depending on the IOU territory in which they live (given disconnection thresholds may be different in each IOU service territory).

Instead, the Commission should consider two alternatives. *First*, the Commission can consider partial payments as qualifying for on-time payments in AMP. This indicates customers' good faith efforts to stay on top of bills while in AMP, even when they may not have the financial resources to pay a bill in full. This maintains the incentive for customers to make regular payments while enrolled, while also keeping disconnection protections. *Second*, the Commission can consider allowing on-time payments (partial or full) to offset the number of missed payments that count towards disenrollment. That is, utilize a customer's successful payments to offset their missed payments. The net number of missed payments would then be used to disenroll a customer rather than the total number of missed payments. For example, if a customer misses their payment on month two of participating, then makes a successful payment on month three, their net missed payments are put back to zero. This would provide more leniency for customers to recover from financial hardship that may occur during AMP participation, would accommodate the lack of predictability in financial hardships, and would increase the likelihood that customers making good faith payments successfully complete the program.

e. The Recommendation that the IOUs Communicate with Customers Prior to Disenrolling them From AMP Regarding Alternative Energy Assistance Programs Should be Adopted

The Commission should adopt the recommendation that the IOUs be required to communicate with customers enrolled in AMP regarding alternative energy assistance programs prior to disenrolling them. CalCCA supports this recommendation because customer communication, outreach, and education are extremely useful for programs like AMP. Customers may not fully understand their payment plan options, how bills work, or what they are eligible for in terms of assistance. If a customer enrolls in AMP and does not complete AMP for any reason, they should still be informed about other assistance options available to them.

f. The Commission Should Not Adopt the Recommendation to Increase the Waiting Period for Customers Disenrolled in AMP to Enroll Again from One to Five Years, or in the Alternative Create Exceptions or an Appeals Process for Customers Under Certain Circumstances

The Commission should not adopt the recommendation to increase the waiting period for customers disenrolled in AMP to reenroll in the program from one to five years. If the Commission does increase the waiting period, it should incorporate exceptions or an appeal process for customers to be able to reenroll earlier under certain circumstances. Currently, AMP has a one-year waiting period for customers who complete the program before they can enroll again. This recommendation comes from a concern that customers will take advantage of perpetual arrearage forgiveness.[29] The AMP evaluation does not provide any quantitative evidence of how many customers may be acting in this way to rationalize increasing the stay-out provision by a factor of five. Concerns of bad actors taking advantage of AMP are themselves reasonable, but this recommendation takes this concern too far, absent quantitative evidence.

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[29] *Id.* at 103-104 (stating that a five-year stay-out provision will ensure customers have re-established good payment patterns and are only re-entering AMP after facing additional hardship).

Completing AMP does not mean a customer is no longer experiencing financial hardship. Financial hardship is neither predictable nor linear, so assuming a customer who completes AMP, receives arrearage forgiveness, then re-enrolls 12, 18, or 24 months later, is taking advantage of the program is misguided. If an IOU finds patterns of customers continuously enrolling and completing AMP two, three, or more times, then the IOUs should engage on a case-by-case basis, or revisit re-enrollment rules when more data are gathered.

If the Commission does adopt this five-year stay-out provision recommendation, it should allow for exceptions and appeals depending on customer situations. PG&E auto-enrolled customers in its 2023 AMP cohort, which led to a group of AMP participants who did not know they were participating and were subsequently removed after non-payment. When the same customers were contacted by their CCA, learned about the program, and attempted to enroll, they were ineligible because they had recently been enrolled and removed from AMP without their knowledge. This example demonstrates the usefulness of exceptions for customers who were auto-enrolled in AMP and then removed without knowing they were in the program in the first place. Other circumstances that warrant re-enrollment sooner than five years likely exist as well, highlighting the need for an exception or an appeals process if the Commission adopts a five-year stay-out provision.

g. Rather than a Bill Insert, the Commission Should Require IOUs to Provide AMP Customers with Current Arrearage Information on the Bill and/or in Customer Online Accounts

The Commission should adopt the AMP Evaluation's recommendation for the IOUs to provide current arrearage information to AMP customers. However, rather than providing such information in a bill insert, the Commission should require the IOUs to provide the original AMP arrearage, the amount forgiven each month, the amount forgiven to date, and the amount remaining ***on the bill.*** The IOUs should also be required to display this information in customer online accounts, if applicable. Bill inserts are easier to miss, especially if customers receive paperless billing. Placing customer AMP participation metrics on a customer bill puts relevant information all in one place, making it easier for customers to stay on top of their bill and see how their arrearage forgiveness is working. The same logic applies to showing AMP participation metrics on customer online accounts. Implementing methods to make tracking AMP participation as clear and easy as possible will help keep customers accountable for their participation.

h. The Recommendation for IOUs to Provide AMP Billing Due Date Reminders Should be Adopted

The Commission should adopt the AMP Evaluation recommendation that IOUs provide AMP participants with reminders one week prior to the bill due date, and after the due date if a payment is missed, via methods the customers have agreed to (*e.g.,* text, email, automated phone calls). Customer messaging and outreach are paramount to keep customers on top of their energy bills and give them the best opportunity to complete AMP. Regular reminders to customers in AMP using approved communication methods is a simple, low-cost method to improve AMP performance.

i. The Recommendation that the Commission Institute a Broad Policy to Require Disconnection of AMP Customers with Missed Payments Under IOU Disconnections Thresholds Should be Rejected

The Commission should reject the AMP Evaluation recommendation to disconnect all customers in alignment with the IOU's current disconnection thresholds if they do not have a documented medical condition. The AMP Evaluation also recommends that prior to implementing this policy, there should be a broad education campaign to inform customers about available assistance, and to inform of timing and phasing in of the new policy based on disconnecting customers with the highest levels of arrearages. CalCCA opposes these recommendations for the same reason it opposes Recommendation 4 above. AMP should operate as a type of disconnection protection, rather than a disconnection accelerator. These recommendations could also require a higher administrative burden than the alternative recommended by CalCCA in response to Recommendation 4. Allowing partial payments to count as a qualifying AMP payment and counting net missed payments as described above will reward good-faith payments while protecting customers from disconnections. These alternative policies also maintain equity across IOU territories that AMP currently provides, rather than subjecting customers to different policies within different IOU territories all administering the same program.

3. Are there other modifications to AMP that the Commission should consider? Why or why not?

CalCCA has no additional recommendations at this time.

C. Procedural Path Forward for CBO Pilot

1. Which of the informal recommendations should the Commission adopt, and which recommendations should the Commission reject? Why?

CalCCA has no comment on the CBO Pilot at this time but reserves the right to respond to results from the informal recommendations on the CBO Pilot.

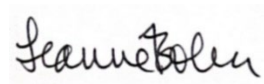
2. Should the Commission require the Large IOUs to file and serve a Tier 2 Advice Letter to implement any changes to the CBO Pilot Program recommended by the final evaluation of the CBO Pilot? If not, how should the Commission review and, where appropriate, implement any recommendations or respond to any issues identified by the final evaluation of the CBO pilot? How will this approach ensure the Commission and interested stakeholders have the opportunity to review the CBO pilot's progress and implement necessary or beneficial changes?

CalCCA has no comment on the CBO Pilot at this time but reserves the right to respond to results from the final recommendations on the CBO Pilot.

III. CONCLUSION

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

Respectfully submitted,



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

November 14, 2025

CALCCA
ADVANCING LOCAL ENERGY CHOICE

CALIFORNIA COMMUNITY CHOICE ASSOCIATION
INFORMAL COMMENTS ON ENERGY DIVISION'S UNFORCED CAPACITY PROPOSAL AND WORKSHOP

I. INTRODUCTION

The California Community Choice Association[1] (CalCCA) appreciates Energy Division's efforts to develop a thoughtful unforced capacity (UCAP) proposal (the Proposal) and host a productive discussion at the Workshop.[2] CalCCA continues to support the California Public Utilities Commission's (Commission) development of a UCAP counting methodology for thermal and storage resources. A UCAP methodology has the potential to: (1) provide better incentives for performance of maintenance on resources to support reliable resource operation; (2) allow load serving entities to assess the reliability of specific resources when making contracting decisions rather than spreading forced outage rates through the planning reserve margin (PRM); and (3) simplify the resource adequacy (RA) program and transition away from complex and ineffective Resource Adequacy Availability Incentive Mechanism (RAAIM) and forced outage substitution rules.

CalCCA generally supports the Proposal, including the proposed use of the California Independent System Operator's (CAISO) Outage Management System data to ensure a complete set of forced outage data. In addition, CalCCA supports the calculation of forced outage rates based upon the availability assessment hours. Finally, CalCCA supports using class averages to provide a complete data set for new resources.

Before the Commission adopts a UCAP methodology, however, several open issues must be resolved. Specifically, the Commission should:

- Quantify UCAP's impacts to the PRM to ensure that the adoption of UCAP will result in equal and opposite adjustments to qualifying capacity (QC) and the PRM;

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

2 *Workshop on Unforced Capacity Methodology and Preliminary Results* (Nov. 3, 2025) (Workshop). Workshop Slides: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/r23-10-011/2025-11-03-ra-workshop-on-ucap-final.pdf.

- Coordinate with the CAISO to clearly define nature-of-work outage codes for UCAP purposes, model known resource characteristics when possible, and reflect capacity unavailability due to forced outages; and

- Further explore historical reporting of ambient derates due to temperature to ensure UCAP values appropriately consider overlapping outages.

In addition, these comments respond to Energy Division's discussion questions regarding how UCAP should be used in planning, operations, and contracting.[3] Specifically, CalCCA recommends the Commission:

- Urge the CAISO to adopt a must-offer obligation consistent with a resource's capability rather than its UCAP value;

- Establish a coordinated process with the CAISO for applying forced outage rates and deliverability adjustments to resource's installed capacity (ICAP); and

- Minimize impacts to existing contracts to the extent practical.

II. COMMENTS ON THE PROPOSAL

A. UCAP Impacts to the PRM Must be Quantified Before Its Adoption to Ensure Equal and Opposite Adjustments to QCs and the PRM

The Commission should quantify UCAP impacts on the PRM to ensure the adoption of UCAP will result in equal and opposite adjustments to QC and the PRM. Capacity accreditation and the PRM are inextricably linked. When using UCAP capacity accreditation, the Commission must ensure that the PRM does not cover forced outages because they are already accounted for in resources' QC.

Decision (D.) 25-06-048 orders Energy Division to continue coordination with the CAISO to develop a final UCAP framework and to "calculate the estimated impact of UCAP on resource counting and to the PRM for procurement."[4] During the Workshop, Energy Division presented estimated impacts of UCAP on resource counting at an aggregate level and stated that it is continuing efforts to identify the impact of the Proposal on the PRM. CalCCA supports continued work on the PRM to identify how the PRM would be impacted before the Commission adopts a

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3 *See* Workshop Slides, at 65-70.

4 D.25-06-048, *Decision Adopting Local Capacity Obligations for 2026-2028, Flexible Capacity Obligations for 2026, and Program Refinements*, Rulemaking (R.) 23-10-011 (June 26, 2025), Ordering Paragraph 7: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M571/K237/571237404.PDF.

UCAP methodology. Once available, the Commission should vet the results of its assessment with parties to ensure the impacts of UCAP on QC values and the PRM are in alignment.

B. The Commission and CAISO Should Seek to Clearly Define Nature-of-Work Outage Codes for UCAP Purposes, Model Known Resource Characteristics When Possible, and Reflect Capacity Unavailability Due to Forced Outages

When determining which nature-of-work outage codes to include in the UCAP calculation, the Commission and CAISO should coordinate to: (1) clearly define nature-of-work outage codes for UCAP purposes; (2) model known resource characteristics, when possible, rather than including them in the UCAP calculation; and (3) reflect capacity unavailability due to forced outages. In its Workshop presentation, Energy Division presented a list of nature-of-work outage codes that are included and not included in its UCAP calculations. CalCCA provides the following recommendations regarding these codes.

First, some nature-of-work outage codes are not defined sufficiently to understand whether they should be included in the UCAP calculation. For example, the "Unit Supporting Start-Up" code could reflect a known resource characteristic, as described below, or may represent a characteristic not represented in the CAISO modeling. In some cases, the start-up of a resource at the same site as another resource may use power from the operating resource to start the other. In such cases, the CAISO should know about this interdependence just as it knows of operating restrictions for multi-stage generators. If the CAISO is not aware of such a restriction, the better result would be for the CAISO to include that data in their market model rather than be surprised by an outage that could have been anticipated.

It is also unclear whether the "Metering/Telemetry," "Remote Terminal Unit," "Inter-Control Center Communications Protocol" result in capacity derates or not. If a communications related outage affects the direct output of the generator and/or its ability to be dispatched by the CAISO, then it should be included in UCAP. The Commission and the CAISO should define each nature-of-work code for UCAP purposes and review each code and its definition with stakeholders to determine if it should be applied to UCAP values.

Second, some nature-of-work outage codes appear to reflect known resource characteristics that the Commission and CAISO should seek to model, rather than include them in the UCAP calculation. For example, "Technical Limitations Not in the Market Model" and "Transitional Limitations" are used to reflect resources' design capabilities to prevent infeasible dispatches. Further, it is not clear that these outages are limiting the NQC of the resource or limiting some other factor for the resource. For example, the Transitional Limitations may be a circumstance in which the resource is taking longer to get through a transition that what the model would ordinarily predict but it will not ultimately limit the NQC of the resource. When possible, the Commission and CAISO should seek to model known resource characteristics rather than including them in the resource's UCAP calculation so that UCAP is reflective of the resource's true availability.

Third, some nature-of-work codes appear to reflect characteristics other than capacity and therefore may not be appropriate to include in a resource's QC. Specifically, the "Ramp Rate" nature-of-work code[5] appears to reflect a decrease in the amount a resource can ramp, rather than the amount of capacity a resource can provide. While this may be something to consider when determining the amount of flexible RA a resource can provide, it does not affect the amount of capacity a resource can provide. Therefore, this code should not be included in the UCAP calculation.

C. Historical Reporting of Ambient Derates Due to Temperature Should be Further Evaluated to Ensure the UCAP Methodology Appropriately Considers Overlapping Outages

The Commission should further explore the historical data reflecting ambient derates due to temperature to ensure the Proposal accurately accounts for resources' availability when there are overlapping ambient derates and forced outages. Energy Division proposes to use separate calculations for ambient derates due to temperature and other types of forced outages. Energy Division will then combine the calculations to derive the UCAP value. While this approach seems reasonable, the Commission should further explore how ambient derates due to temperature have been reported historically, to ensure overlapping outages are appropriately reflected in the UCAP value.

CalCCA agrees with commenters at the Workshop that more discussion is needed about how to treat overlapping ambient derates due to temperature and other forced outages. For example, if there is a resource with a 100 megawatts (MW) Pmax, a two percent forced outage rate, and a 10 percent ambient derate, should the resource's UCAP equal 90 MW or 88 MW? Discussion during the Workshop suggests that further investigation into the data used to calculate forced outage rates and ambient derates is warranted to ensure overlapping outages are accounted for in a manner that accurately reflects the availability of the resource.

III. RESPONSE TO ENERGY DIVISION'S QUESTIONS REGARDING UCAP APPLICABILTIY

A. The Commission Should Urge the CAISO to Adopt a Must-Offer Obligation Consistent with a Resource's Capability Rather Than Its UCAP Value

A resource's must-offer obligation should be consistent with its total shown capability, not its UCAP value. Some parties at the Workshop seemed to suggest otherwise. These

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[5] The CAISO defines a "Ramp Rate" nature-of-work outage code as an adjustment to the ramp rate value for a resource[;] value must be between the minimum and maximum values defined for the resource." *See* CAISO, *Business Practice Manual for Outage Management*, Version 31 (June 30, 2025), at 24: https://bpmcm.caiso.com/BPM%20Document%20Library/Business%20Practice%20Manual%20for%20BPM%20Change%20Management/Outage%20Management%20BPM_Version_31_Clean.docx.

suggestions obviate the benefits of a UCAP framework by not requiring resources to bid their full capability.

A resource's must-offer obligation should be consistent with the entire amount of shown capacity that is available (*i.e.*, not on forced outage). For example, if a 100-MW resource with a 5 percent forced outage rate is shown for its full 95 MW of UCAP NQC, then it must then bid 100 MW of capacity into CAISO's markets when the resource is not on outage. This must-offer obligation is necessary to ensure sufficient capacity is available to the system at all times by accounting for the fact that some resources will be on forced outage and some will not. This is consistent with other markets that use UCAP and require energy market offers to the amount of ICAP.[6]

Absent this requirement, resources would need to be available 100 percent of the time to their UCAP values, which is an unreasonable assumption. In the alternative, substitute capacity would need to be provided, which defeats one of the purposes of UCAP to ensure the market is offered the full amount of required RA.

This is conceptually similar to effective load carrying capability (ELCC) or exceedance values. Those values represent an expected output based on the installed capacity. The ELCC or exceedance value does not replace the must-offer obligation. If it did, the system would never obtain the full value of the ELCC or exceedance. Therefore, requiring bidding up to the full amount of shown capacity that is available is consistent with the must-offer obligation for variable energy resources. For example, a solar resource's pMax is derated using the exceedance methodology to obtain the QC. A solar resource's must-offer obligation is its entire availability, not its derated amount. This ensures that overall, the solar resource provides enough capacity to derive the static exceedance value.

B. A Coordinated Commission and CAISO Process Should be Adopted for Applying Forced Outage Rates and Deliverability Adjustments to a Resource's ICAP

Energy Division asked the Workshop participants to discuss when UCAP should be used in planning and operations and when it should not.[7] CalCCA agrees with Energy Division that, "UCAP should not be used in deliverability feasibility studies because the unit will not always

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[6] "Generators that are Capacity Resources and have an RPM or FRR commitment for the next Operating Day and are self-scheduling shall submit offer data in the event that they are called upon during emergency procedures. Such offers shall be based on the ICAP equivalent of the cleared UCAP capacity commitment." PJM Manual 11: Energy & Ancillary Services Market Operations at 27: https://www.pjm.com/-/media/DotCom/documents/manuals/m11.pdf.

[7] Workshop Slides, at 66-69.

have a forced outage, and it will have an output higher than UCAP such as pMax or [net deliverable capacity]."[8]

To do this, the QC should be derated by the UCAP. Deliverability will then be applied to a QC after the UCAP and may further derate the resource if it is not fully deliverable. For example, if a 100-MW resource has a 10 percent derate due to UCAP, and during the interconnection process, the resource was fully deliverable, the ICAP would be equal to 100 MW and the UCAP would be 90 MW. Since up to 100 MW is deliverable, the most binding constraint is the UCAP. Therefore, the resource's NQC would be 90 MWs. As a second example, suppose the same resource was only partially deliverable at 50 percent. In this case, the ICAP would be 100 MW, the UCAP would be 90 MW and the NQC would be 50 MW to reflect the deliverability constraint as the most binding.

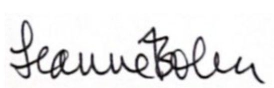
C. UCAP's Impacts on Existing Contracts Should be Limited to the Extent Practical

Energy Division also asked parties to describe how (if at all) will existing and future contracts need to change to pass on the performance incentive of the UCAP framework.[9] To the extent practical, the Commission should seek to minimize impacts on existing contracts. The Commission should, therefore, seek to use existing terminology as those terms are often used in formulating contracts. To do this, the QC should be derated by the UCAP and NQC should remain the value that can be purchased and shown for RA.

IV. CONCLUSION

CalCCA thanks the Commission for the productive conversation during the Workshop and urges the Commission to consider the recommendations herein.

Respectfully submitted,



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

cc: Service Lists: R.23-10-011 and R.25-10-003

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8 Workshop Slides, at 66.
9 *Id.* at 70.

California Community Choice Association

SUBMITTED 11/26/2025, 11:38 AM

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

1. Please provide a summary of your organization's general comments on the materials shared and subsequent discussion during the Nov 12 meeting.

The California Community Choice Association (CalCCA) appreciates the opportunity to comment on the California Independent System Operator's (CAISO) Storage Design and Modeling Working Group Meeting. In summary, the CAISO should:

- Adopt CalCCA's alternative resource adequacy (RA) accounting proposal for storage resources with foldback included in their PMax, if the CAISO puts forth a proposal in the California Public Utilities Commission's (CPUC) RA proceeding;
- Prioritize the development of a Master File parameter as a market-based solution to reflecting foldback in the market and ensuring known resource characteristics are modeled rather than reflected in a resource's unforced capacity value;
- Adopt the stakeholder-supported, principle-based approach in which negative revenues attributed to market algorithms or CAISO action may warrant uplift and negative revenues attributed to bidder behavior may not warrant uplift;
- Require the submission of the day-ahead initial state-of-charge (SOC) parameter within a certain accuracy range to be eligible for bid cost recovery (BCR); and
- Do not exempt storage resources from local Market Power Mitigation (MPM) and instead seek to enhance the tools and methodologies used to manage storage resources in the market and provide uplift payments when warranted.

2. Provide your organization's comments regarding the initiative's overview and schedule.

CalCCA has no comments at this time.

3. Provide your organization's comments regarding the update on nonlinearity.

The CAISO's proposed path forward addresses two issues: (1) reflecting foldback in the CPUC RA qualifying capacity (QC) calculation; and (2) reflecting foldback in CAISO market optimization.

The CAISO should adopt CalCCA's alternative RA accounting proposal for storage resources with foldback included in their PMin to PMax range if the CAISO puts forth a proposal in the CPUC's RA proceeding. CalCCA understands that the CAISO plans to propose a QC methodology that accounts for foldback in the CPUC's Rulemaking (R.) 25-10-003, on January 23, 2026. The CAISO's proposed calculation would divide the amount of energy the resource can provide *unaffected by foldback* by four (for a four-hour battery). This will discount the RA counting for the resource for *all hours* it can be shown. This is not reflective of the nature of foldback and would overly constrain the RA value a resource can provide in the hour of greatest need. This is particularly important given the slice-of-day (SOD) nature of the CPUC RA system in which an LSE must demonstrate sufficient capacity to serve load in all 24 hours of the "worst day" of the month. Using an average rather than values that can be provided will unnecessarily discount resources in some hours in which the resource is available to reliably serve grid needs.

Instead, if the CAISO makes a proposal in the CPUC's RA proceeding to account for foldback in the CPUC's QC calculation, it should modify its proposed calculation to allow a resource to count for full capacity for three of the four hours and a derated amount in the fourth hour. Under the SOD framework, an LSE can claim the full amount of capacity for a single hour but may not need the full capacity in other hours. CalCCA's proposed alternative calculation would result in a higher RA counting in the hour of highest need, and more accurately reflect the impacts of foldback on RA capacity.

The example below compares the CAISO's proposal with CalCCA's proposed alternative assuming a resource with a 25 megawatts (MW) nameplate, 90 megawatt hours (MWh) available, and 10 MWh unavailable due to foldback.

- The CAISO's proposed calculation
    - NQC = 90MWh/4 hours = 22.5 MW
    - SOD Showing: No greater than 22.5 MW in any hour
- CalCCA's proposed alternative
    - NQC = 25 MW
    - SOD Showing: MW in hour 1 + MW in hour 2 + MW in hour 3 + MW in hour 4 cannot exceed 90 MWh

Under CalCCA's alternative proposal, the NQC will equal 25 MW (nameplate), and the total energy in all hours shown will not exceed 90 MWh. In this case, that means the resource can be shown for 25 MWs in hours 1 – 3, resulting in a total of 75 MWh and leaving 15 MW available for the fourth hour. The result is a maximum amount of 25 MW in any hour, limited by energy. Under this proposal, an LSE could show the resource for 22.5 MW in each hour and get the same result as the CAISO's proposal but could also show up to an addition 2.5 MWs in three hours from the resource as long as the total showing does not exceed the resource's energy limit. If the CAISO proposes derating a resource's capacity value to account for foldback, it should do so using CalCCA's alternative proposal and apply it only to resources whose PMax includes the foldback range.

This proposal will also work for resources that are not constrained by foldback. For example, if the resource has a 25 MW peak capacity and sufficient storage to provide 110 MWh, then the foldback never occurs and the energy limit is never reached meaning that the resource can be counted for 25 MWs in all four hours.

Market Optimization

The CAISO should prioritize the development of a Master File parameter as a market-based solution reflecting foldback in the market and ensuring known resource characteristics are modeled rather than reflected in a resource's unforced capacity value. The CAISO proposes an interim and long-term proposal for addressing foldback in the market optimization. The interim proposal would result in the market optimization being unable to access the resources' foldback range. As described in section 4, below, unnecessarily making energy in the foldback range unavailable to the market when foldback ranges are not static is a negative outcome for reliability, ratepayers, and storage owners.

Any interim approach should continue to allow the market to access the foldback range, when the resource is available within that range. A better alternative would be to maintain the status quo in the interim, in which storage resources reflect foldback ranges with outage cards and prioritize the CAISO's long-term solution of a Master File parameter to reflect foldback in the market. CalCCA has previously advocated for the "Technical Limitations Not in the Market Model" Resource Adequacy Availability Incentive Mechanism (RAAIM) exempt outage card to be used and continues to support that approach for the reasons described in CalCCA's September 5, 2025, comments.[1] More important than the type of outage card used in the interim, however, is prioritizing a Master File parameter as a market-based solution to reflecting foldback in the market and ensuring known resource characteristics are modeled rather than reflected in a resource's unforced capacity value.

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[1] https://stakeholdercenter.caiso.com/Comments/AllComments/a35d7182-e62e-4559-93c0-80ede736ceba#org-a3c4805c-db85-45ec-b58c-a9ccff090a32.

4. Provide your organization's comments regarding the presentation offered by REV Renewables.

CalCCA agrees with Rev Renewables that unnecessarily making energy in the foldback range unavailable to the market when foldback ranges are not static is a negative outcome for reliability, ratepayers, and storage owners. As stated in section 3, the CAISO should prioritize developing Master File fields for resources to reflect foldback ranges in the market model.

5. **Provide your organization's comments regarding the guiding principles related to the Uplift & Default Energy Bid (DEB) topic group.**

CalCCA supports the CAISO eliminating opportunities for strategic bidding to inflate BCR payments. CalCCA agrees with the stakeholder-supported, principle-based approach in which negative revenues attributed to market algorithms or CAISO action may warrant uplift, and negative revenues attributed to bidder behavior may not warrant uplift.

6. **Provide your organization's comments regarding the responses on Day-Ahead Uplift and Initial State-of-Charge (SOC) as part of the Uplift & Default Energy Bid (DEB) topic group.**

CalCCA reiterates its October 13, 2025, comments.[1] Specifically, the CAISO's solution should adhere to the principle, rather than institute a blanket elimination of day-ahead BCR, unless the CAISO can demonstrate all cases of day-ahead BCR are driven by scheduling coordinator action rather than CAISO market or operator action.

CalCCA directionally supports the CAISO's proposal to require the submission of the day-ahead initial State of Charge (SOC) parameter within a certain accuracy range to be eligible for BCR. In general, scheduling coordinators (SC) should be responsible for accurately reflecting their resources' characteristics rather than relying on a default value. CalCCA supports adopting a mechanism to incent submissions within a pre-defined accuracy range, though it does not take a position on which proposed mechanism should be adopted among the CAISO, California Energy Storage Alliance, and Vistra Corp. (Vistra) proposals.[2] If an SC does not select a value despite the requirement to do so, then the CAISO should include a default value. If the default value is outside the accuracy range, the resource should be ineligible for uplift.

[1] https://stakeholdercenter.caiso.com/Comments/AllComments/c9903a4c-a900-47d2-b362-51c768a52e73#org-57fb586b-0cfd-4b02-a180-1b0262593a0f.

[2] *Storage Design and Modeling, Working Group on Outage Management, Uplift & DEB and Mixed-Fuel & Distribution Level Resources* (Nov. 14, 2025) (CAISO Presentation), at Slide 45.

7. **Provide your organization's comments regarding Real-Time Uplift and Proposed Approaches as part of the Uplift & Default Energy Bid (DEB) topic group.**

CalCCA supports a real-time uplift approach aligned with the principle discussed in section 5, above. The data provided by the CAISO and the Department of Market Monitoring clarifies the magnitude of out-of-merit dispatches resulting from the multi-interval optimization (MIO) and the comparison of net revenues under the MIO and a counterfactual no-MIO scenario. The overall BCR methodology for storage should consider MIO out-of-merit dispatches and provide resources make-whole payments if they experience net losses over the day. However, a specific uplift payment for MIO out-of-merit dispatches without consideration of net losses over the day, as suggested by some stakeholders, is unnecessary and unsupported.

Instances of MPM may warrant uplift if a resource bids to preserve its output until later in the day, but the bid is mitigated, causing the resource to be dispatched when it otherwise would not have been. On the other hand, instances of MPM may not warrant uplift if the resource is rightfully mitigated to avoid the abuse of market power. For the reasons described in section 11, the CAISO should not cease local MPM for storage assets as a means to eliminate the need for a real-time uplift mechanism because MPM plays a role in protecting ratepayers from the exercise of market power.

8. **Provide your organization's comments regarding the notion of establishing a form of System SOC target or constraint, including your perspective on how the SOC target should be established and the relationship this target or constraint would have with market products.**

CalCCA has no comments at this time.

9. **Provide your organization's comments regarding the potential modifications to the storage DEB to enable the representation of real-time conditions and ease its use across different geographies.**

   CalCCA has no comments at this time.

10. **Provide your organization's comments regarding the presentation offered by Pacific Gas & Electric (PG&E).**

   CalCCA has no comments at this time.

11. **Provide your organization's comments regarding the presentation offered by Vistra, including the discussion questions included in their materials.**

   CalCCA appreciates Vistra's presentation and acknowledges the challenges with managing use-limited storage resources in the CAISO market. However, CalCCA does not support exempting storage resources from local MPM under Vistra's proposed self-management option. MPM is a critical component of the CAISO's market design to prevent suppliers from exerting market power, maintain competitive market outcomes, and ensure just and reasonable rates for customers. While there are other resource types to which MPM is not applied, these resources are: (1) not fully integrated into the CAISO market (e.g., certain investor-owned utility-run load reduction programs); (2) called upon only in emergencies (e.g., reliability demand response resources); (3) bid but based on the value to load, with bids being struck primarily where other marginal cost based supply has run out or load is willing to curtail at a price lower than the marginal resource (e.g. proxy demand response); or (4) should be subject to MPM pending the development of a DEB (e.g., hybrid resources). The CAISO should therefore seek to enhance the tools and methodologies used to manage storage resources in the market and provide uplift payments *without exempting the technology from MPM*.

12. **Provide your organization's comments regarding the presentation offered by Cong Chen Ph.D., Assistant Professor, Thayer School of Engineering, Dartmouth College.**

   CalCCA has no comments at this time.

13. **Provide your organization's comments regarding the update provided regarding the high sustainable limit (to ease the development of comments, please note that a more detailed review of the proposed guidance is included in the materials presented September 29, 2025).**

   https://stakeholdercenter.caiso.com/InitiativeDocuments/Presentation-Storage-Design-and-Modeling-Sep-29-2025.pdf

   CalCCA has no comments at this time.

14. **Provide your organization's comments regarding the update and materials on outage reporting for distribution-level resources. This topic will be discussed during the next stakeholder meeting (scheduled for Dec. 4)**

   CalCCA supports the CAISO's proposed changes to this element.

15. **Provide your organization's comments regarding the materials and upcoming discussion on the co-located variable energy resource Follow DOT topic. This topic will be discussed during the next stakeholder meeting (scheduled for Dec. 4).**

    CalCCA has no comments at this time.

16. **Provide your organization's comments regarding the upcoming discussion on mixed-fuel ancillary services. This topic will be discussed during the next stakeholder meeting (scheduled for Dec. 4).**

    CalCCA has no comments at this time.

17. **Please provide any additional comments, feedback, or examples in the Nov 12 stakeholder meeting. You may upload examples or data using the Attachments field below.**

    CalCCA has no additional comments at this time.

DECEMBER FILINGS

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2026 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U 39 E)	Application No. 25-05-011 (Filed May 15, 2025)
Expedited Application of Pacific Gas and Electric Company Pursuant to the Commissions Approved Energy Resource Recovery Account (ERRA) Trigger Mechanism (U 39 E)	Application No. 25-09-015 (Filed September 30, 2025)

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON PROPOSED DECISION

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

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

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

Counsel to
CALIFORNIA COMMUNITY CHOICE ASSOCIATION

December 1, 2025

SUBJECT MATTER INDEX

TABLE OF AUTHORITIES

SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS[1]

With respect to the valuation of pre-2019 banked RECs for departed load, CalCCA recommends that the PD be modified to:

- Reject PG&E's pre-2019 banked REC zero valuation proposal which violates section 366.2(g)'s requirement that departed load customers receive the *value* of any benefits associated with PG&E's PCIA resources when those benefits remain with bundled service customers;

- Consistent with section 366.2(g), Commission precedent, and prior PG&E practice, value pre-2019 banked RECs at the applicable RPS Adder in the year in which PG&E uses the RECs for RPS compliance, when crediting customers based on their PCIA vintage, either permanently or on an "interim" basis pending consideration of the issue in Phase 2 of the PCIA proceeding;

- Direct PG&E to exhaust its post-2019 banked RECs before using any pre-2019 banked RECs towards its Minimum Retained RPS requirement—80 percent of the utility's 2025 shortfall can be met with these non-controversial RECs; and

- Direct PG&E to track and report not only the pre-2019 banked RECs it uses to meet 2026 compliance, but also any pre-2019 banked RECs it uses to meet ***2025*** compliance. This information will allow any updated guidance from the Commission in the PCIA proceeding regarding the treatment of pre-2019 banked RECs to apply to all pre-2019 banked RECs used for compliance in *both* 2025 and 2026.

CalCCA also recommends the following additional PD modifications regarding its adoption of SCE's interim RA Slice-of-Day methodology:

- While CalCCA does not oppose the PD's conclusion directing PG&E to implement SCE's interim RA Slice-of-Day method until the impacts of Slice-of-Day on the PCIA framework are conclusively resolved in a rulemaking, the Commission should direct PG&E to file a Tier 2 advice letter detailing its implementation of SCE's method within thirty days of its final decision in this proceeding; and

- A clarifying edit on page 35 is also needed. The PD states: "PG&E has sufficient information to apply PG&E's methodology; they would apply their current methodology for calculating the RA sales, unsold and retained RA volumes." The PD should be revised to say: "PG&E has sufficient information to apply SCE's methodology; ***PG&E*** would apply ***SCE's*** current methodology for calculating the RA sales, unsold and retained RA volumes;"

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

CalCCA also recommends the following additional PD modification:

- The Commission should memorialize CalCCA and PG&E's uncontested agreement that data center load in CCA service territory defaults to CCA service.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

California Community Choice Association[2] (CalCCA) submits these Comments on Administrative Law Judge Fox's *[Proposed] Decision Approving Pacific Gas and Electric Company's 2026 Energy Resource Recovery Account Related Forecast Revenue Requirement and 2025 Electric Sales Forecast* (PD) pursuant to Rule 14.3 of the Rules of Practice and Procedure of the California Public Utilities Commission and the procedural schedule established in the Assigned Commissioner's Scoping Memo and Ruling (confirmed by the Administrative Law Judge's

[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.

November 24, 2025, E-Mail Ruling Clarifying Comment Due Dates), which modifies the time periods for comments and reply comments prescribed by Rule 14.3.[3]

I. INTRODUCTION

With little mention of its impacts on millions of California families, the PD breezes past the enormous electricity rate increases it approves for community choice aggregator (CCA) customers who have departed bundled service from Pacific Gas & Electric Company (PG&E). Earlier this year in the Power Charge Indifference Adjustment (PCIA) Track One rulemaking (R.25-02-005), the Commission adopted a revised methodology for calculating the resource adequacy (RA) market price benchmark (MPB) after the investor-owned utilities (IOUs), including PG&E, complained that the methodology that had benefitted bundled customers for many years since its adoption in D.18-10-019 needed changes.[4] This PD incorporates that new methodology into PCIA rates.

To add insult to injury, the Commission through this PD layers on an *additional* benefit to PG&E bundled customers, at the expense of departed load customers, by adopting PG&E's *proposal* to provide ***no value*** to departed load customers for renewable energy credits (RECs) being used by PG&E but paid for by those departed load customers. This change is unnecessary and premature, given the pending PCIA Track 2 proceeding. In addition, the PD violates the requirement in Public Utilities Code section 366.2(g)[5] that such value be provided to departed customers. The PD's adoption of PG&E's proposal is also contrary to prior Commission decisions, including PG&E's 2025 Energy Resource Recovery Account (ERRA) Forecast Decision, in which the Commission approved PG&E's proposal to value banked RECs (including the same vintage

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3 Assigned Commissioner's Scoping Memo and Ruling at 5 (Jul. 31, 2025) (Scoping Memo).

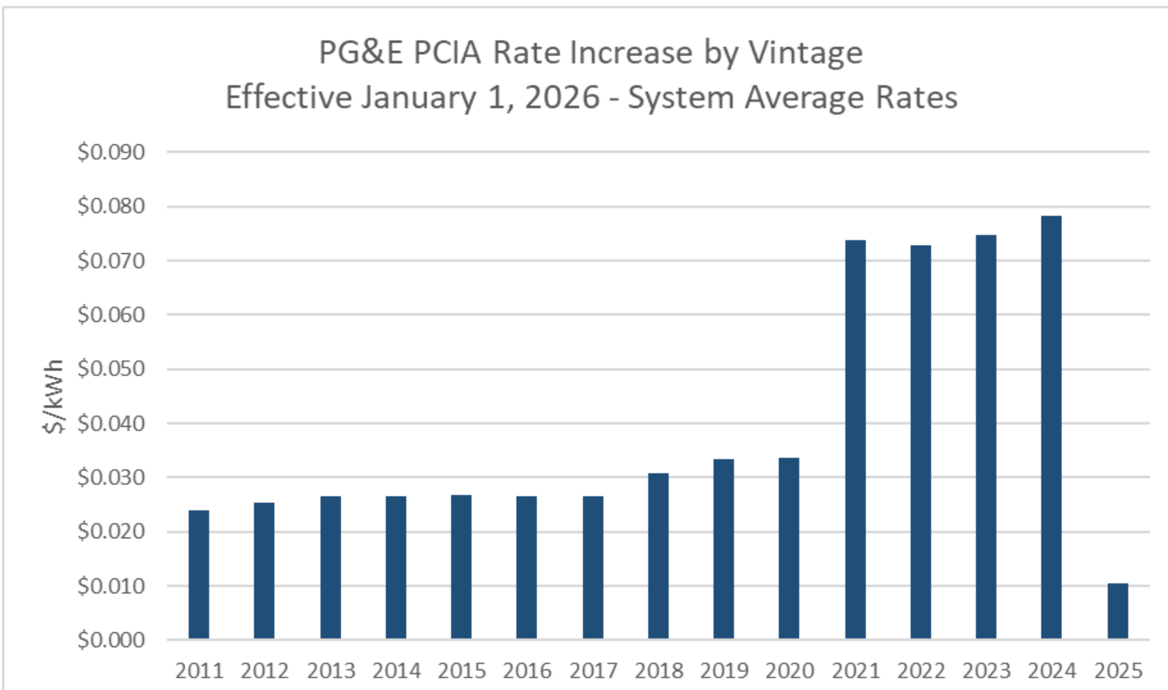
4 Decision (D.) 25-06-049.

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

of RECs at issue here—pre-2019 banked RECs) and credit the departed load customer vintages corresponding to the year in which those RECs were generated.[6]

The result of this pile of new policies, along with market forces increasing PCIA rates, is substantial for departed load customers who, like all California customers, are struggling with the affordability of electricity rates. As the figures below demonstrate, PCIA rates will *skyrocket* in 2026 for departed load customers across all vintages,[7] with customers in vintages 2021-2024 being the hardest hit:

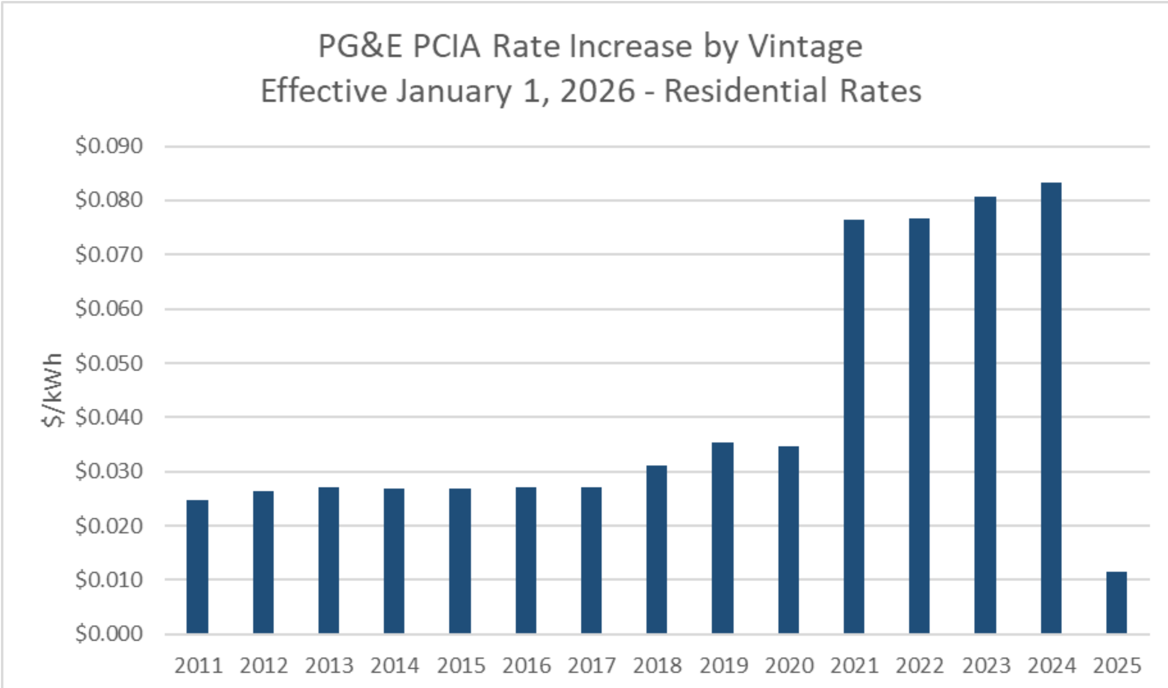
Figure 1: PCIA Rate Increase Approved in the PD, by Vintage (System Average Rates)



[6] D.24-12-038 at Conclusion of Law (COL) 1.

[7] Note the PD distorts and understates the PCIA rate increases customers will experience in 2026 by comparing proposed rates to rates effective March 1, 2024 (rather than January 1, 2025). *See* PD at 50-51.

Figure 2: PCIA Rate Increase Approved in the PD, by Vintage (Residential Rates)



Overall, customers purchasing their electricity from CCAs will see their cost responsibility for the PCIA increase by a staggering ***455 percent*** from 2025 to 2026.[8] The change in the PCIA cost responsibility for these departed customers is almost ***ten times*** larger than the change in the cost responsibility for bundled customers.[9]

The shift in cost responsibility will be difficult for all departed customers, including many in disadvantaged communities. For example, much of Stockton, California, is comprised of disadvantaged, low-income communities under the State of California's guidelines.[10] The PCIA rates for departed load customers will increase by more than ***eight cents per kilowatt-hour***. On

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8 California Community Choice Association's Comments on Pacific Gas and Electric Company's Fall Update Testimony at 5 (Nov. 10, 2025).

9 *Ibid*.

10 *See* State of California, OEHHA, California Climate Investments Priority Populations Map 4.0 (showing Stockton as a disadvantaged community (low-income)): https://gis.carb.arb.ca.gov/portal/apps/experiencebuilder/experience/?id=5dc1218631fa46bc8d340b8e82548a6a&page=Priority-Populations-4_0.

average, this will result in an over ***$41 per month*** increase in the PCIA portion of customers' bills, equating to an enormous ***$492 annual increase***.[11] Table 2 shows other communities facing similar rate hikes, including Nevada City and Los Banos, which are also comprised of disadvantaged and/or low-income communities:[12]

Table 1: PCIA Rate Increases Approved in the PD – Example Impacts[13]

Community	Monthly Bill Increase[14]	Annual Increase
Los Banos, CA	$43.91	$526.92
Stockton, CA	$41.00	$492.00
Nevada City, CA	$32.11	$385.31

Aside from the significant rate impacts, the PD's adoption of PG&E's pre-2019 banked REC proposal simply constitutes legal error and must be modified. To ensure both bundled and departed load remain indifferent from a customer departing bundled service, Public Utilities Code section 366.2(g) *requires* that departed load customers receive the value of any benefits associated with PG&E's PCIA resources when those benefits remain with bundled service customers. Here, PG&E is using pre-2019 banked RECs for its RPS compliance on behalf of its bundled customers.

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11 This figure is derived from the following formula which, per Ava Community Energy, relies on average monthly residential electricity usage in Stockton of approximately 500 kWh: $41.00 = $0.08200/kWh increase in the PCIA for Vintage 2024 times 500 kWh. The annual increase is derived from the following: $41/per month * 12 months.

12 *See* State of California, OEHHA, California Climate Investments Priority Populations Map 4.0 (showing Stockton as a disadvantaged community (low-income)): https://gis.carb.arb.ca.gov/portal/apps/experiencebuilder/experience/?id=5dc1218631fa46bc8d340b8e82548a6a&page=Priority-Populations-4_0.

13 These figures have been confirmed by the relevant CCA and utilize the same formula as the figures for Stockton in note 11, *supra*. 405 kWh is used as the average household usage for Nevada City, a Vintage 2023 community ($0.07928/kWh PCIA increase). 585 kWh is used as the average household usage for Los Banos, a Vintage 2021 and 2022 community (using 2022, that is a $0.07506/kWh PCIA increase).

14 The Monthly Bill Increase assumes the relevant CCA does not put in place any ratepayer protection mechanism to manage its customers' rate increases.

Those pre-2019 banked RECs were paid for by bundled customers at the time the RECs were generated, and then "banked" by PG&E for later use. PG&E now seeks to use those RECs, and therefore is statutorily required to provide *value* to now-departed customers who paid for the credits in the form of a credit through the PCIA.

PG&E and the Commission have previously followed these statutory requirements. Without any explanation or reasoning, the PD essentially reverses the Commission's decision in PG&E's 2025 ERRA Forecast case, which approved PG&E's proposal to value banked RECs (including pre-2019 banked RECs) and credit the PCIA vintages corresponding to the year in which those RECs were generated.[15] By allowing PG&E's about-face with its new proposal to succeed, the PD not only continues to pile on the rate impacts for unbundled customers, but clearly violates section 366.2(g).

The PD adopts PG&E's proposal on an "interim basis" given the "expedited nature" of this proceeding, and states that the proposal to "address conflicting understandings" regarding the valuation of the pre-2019 banked RECs should be considered in a rulemaking (presumably the PCIA rulemaking).[16] The PD then directs a process for tracking RECs used to meet 2026 compliance "until further Commission guidance is put into place."[17]

The PD's adoption of PG&E's proposal on an interim basis, however, fails to salvage the PD's unlawful conclusion for three reasons. First, the REC tracking process the PD directs would do nothing to ensure departed customers are appropriately compensated for the pre-2019 banked RECs PG&E proposes to use in ***2025***. Second, nothing in the law permits temporary cost shifts. The Commission must adopt a methodology here that complies with section 366.2(g). Third, the

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15 *See* D.24-12-038 at COL 1.

16 PD at 28-29.

17 *Id*. at 28-29.

PD's conclusion adopting PG&E's methodology on an interim basis is arbitrary. The PD does not support its conclusion with any reasoning or discussion of the record evidence. The PD only implies that a promise to potentially revamp the methodology in the future is sufficient to comply with the law. It is not. To the extent the Commission wishes to apply any "interim methodology" now, it should continue to value the pre-2019 banked RECs in a manner consistent with section 366.2(g) and Commission precedent.

The Commission has the record it needs to resolve this issue conclusively now. Therefore, with respect to the valuation of pre-2019 banked RECs for departed load, CalCCA recommends that the PD be modified to:

- Reject PG&E's pre-2019 banked REC zero valuation proposal which violates section 366.2(g)'s requirement that departed load customers receive the *value* of any benefits associated with PG&E's PCIA resources when those benefits remain with bundled service customers;

- Consistent with section 366.2(g), Commission precedent, and prior PG&E practice, value pre-2019 banked RECs at the applicable RPS Adder in the year in which PG&E uses the RECs for RPS compliance, when crediting customers based on their PCIA vintage, either permanently or on an "interim" basis pending consideration of the issue in Phase 2 of the PCIA proceeding;

- Direct PG&E to exhaust its post-2019 banked RECs before using any pre-2019 banked RECs towards its Minimum Retained RPS requirement; and

- Direct PG&E to track and report not only the pre-2019 banked RECs it uses to meet 2026 compliance, but also any pre-2019 banked RECs it uses to meet ***2025*** compliance. This information will allow any updated guidance from the Commission in the PCIA proceeding regarding the treatment of pre-2019 banked RECs to apply to all pre-2019 banked RECs used for compliance in *both* 2025 and 2026.

CalCCA also recommends the following additional PD modifications regarding its adoption of Southern California Edison Company's (SCE) interim Resource Adequacy (RA) Slice-of-Day (SoD) methodology:

- While CalCCA does not oppose the PD's conclusion directing PG&E to implement SCE's interim RA SoD method until the impacts of SoD on the PCIA framework are conclusively resolved in a rulemaking, the Commission should direct PG&E to file a Tier 2 advice letter detailing its implementation of SCE's method within thirty days of its final decision in this proceeding; and

- A clarifying edit on page 35 is also needed. The PD states: "PG&E has sufficient information to apply PG&E's methodology; they would apply their current methodology for calculating the RA sales, unsold and retained RA volumes." The PD should be revised to say: "PG&E has sufficient information to apply SCE's methodology; ***PG&E*** would apply ***SCE's*** current methodology for calculating the RA sales, unsold and retained RA volumes;"

CalCCA further recommends the following additional PD modification:

- The Commission should memorialize CalCCA and PG&E's uncontested agreement that data center load in CCA service territory defaults to CCA service.

II. THE PD SHOULD BE MODIFIED TO REQUIRE THAT PG&E CONTINUE VALUING PRE-2019 BANKED RECS CONSISTENT WITH PUBLIC UTILITIES CODE SECTION 366.2(G), COMMISSION PRECEDENT, AND PG&E'S EXISTING PRACTICE

The PD commits legal error by adopting PG&E's pre-2019 banked REC valuation proposal. Public Utilities Code section 366.2(g) requires that departed load customers receive the value of any benefits of PG&E's PCIA resources when those benefits remain with bundled customers. This requirement is effectuated in the PCIA framework by applying the appropriate MPB to the sources of value in the IOU's PCIA portfolio. Accordingly, per the PCIA framework, departed load receives the value of PG&E's RPS-eligible resources retained for bundled customer compliance by applying the RPS Adder to the volume of "Retained RPS" generation. What the Commission now labels as "Retained RPS" has been treated the same since the Commission created a new MPB to reflect the RPS value of certain RPS-eligible resources fifteen years ago, in D.11-12-018. Per that decision, RECs retained for the benefit of bundled customers are valued at the applicable RPS Adder. To the extent the REC was previously purchased by bundled customers at the time it was generated, the value of that REC is credited to the PCIA vintage corresponding to the year it was generated to ensure both bundled and unbundled customers are treated fairly.

PG&E's banked REC proposal in this proceeding fails to comport with section 366.2(g), Commission precedent implementing the indifference framework established in California law (including D.19-10-001 and its predecessors), and PG&E's previous practice. PG&E proposes to apply pre-2019 banked RECs towards bundled customer compliance while denying departed load their fair share of the value of those RECs. Stated simply, PG&E's current bundled customers in 2026 should be responsible for the cost of RPS compliance on their behalf in 2026. And unbundled customers should receive credit for the value of RPS attributes they previously paid for but that are now being used for bundled customer RPS compliance. If previously banked RECs are used for current bundled customer compliance, there must be a credit in PG&E's Indifference Amount that conveys the portion of the value of those RECs to departed load. This ensures that the cost of bundled customer compliance is not shifted to departed load customers and that the value of resources departed load customers paid for originally is received by those customers. By adopting PG&E's banked REC proposal, the PD permits bundled customers to apply RECs towards their RPS compliance requirements, while denying fair compensation to departed load customers who paid for a portion of those RECs. That methodology is not only unfair, it is plainly unlawful.

The fact that the PD adopts PG&E's proposal on an "interim basis" and directs a process for tracking RECs used to meet 2026 compliance does not remedy the PD's legal error. First, as CalCCA described in its comments on PG&E's Fall Update, PG&E forecasts using pre-2019 banked RECs to meet not only its 2026, but also its 2025 RPS requirements. Despite previously proposing to value pre-2019 banked RECs at the 2025 RPS Adder and credit the vintage corresponding to the year in which the banked REC was generated, PG&E now proposes to use pre-2019 banked RECs to meet its 2025 shortfall without any credit to the PCIA. The departed customers who paid for a portion of those banked RECs will never receive *any* value for those

RECs under the process the PD prescribes, which directs PG&E to track the pre-2019 banked RECs it will use to meet only *2026* compliance requirements.

Second, nothing in the law permits temporary cost shifts. Section 366.2(g) requires the Commission to ensure that departed customers receive the value of benefits that remain with bundled service customers. Neither that statute, nor any other statute, permits the Commission to deny or to keep customers indefinitely waiting for that value.

Third, the PD's conclusion adopting PG&E's proposal is arbitrary. It wholly ignores the hundreds of pages of testimony and briefing on this issue and fails to support its conclusion with any reasoning. Worse, the PD—without any explanation or reasoning—essentially reverses the Commission's decision in PG&E's 2025 ERRA Forecast case, which approved PG&E's proposal to value banked RECs (including pre-2019 banked RECs) and credit the PCIA vintages corresponding to the year in which those RECs were generated.[18] In other words, whereas the Commission approved PG&E's proposal to ***value*** the pre-2019 banked RECs it would use to meet the shortfall towards its 2025 Minimum Retained RPS requirement, the PD would *undo* that Decision (without explanation) and permit PG&E to assign ***no value*** to the pre-2019 banked RECs used to meet that very shortfall.

The PD is also internally inconsistent because it defers the merits of PG&E's and CalCCA's proposed banked REC valuation methodologies to a separate proceeding while simultaneously approving a methodology that departs from the status quo. In prior years, PG&E has consistently valued banked RECs, including pre-2019 banked RECs, at the applicable MPB in the year in which it uses those RECs, and credited the PCIA vintage(s) corresponding to the year in which the banked RECs were generated.[19] The Commission has repeatedly approved that

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[18] D.24-12-038 at COL 1.

[19] *See* CalCCA Opening Brief at 34-36.

approach.[20] It is illogical to conclude, on the one hand, that the appropriate valuation of pre-2019 banked RECs must be addressed in a future rulemaking, and adopt, on the other hand, an interim methodology that departs from an existing, Commission-approved practice. CalCCA's proposed pre-2019 banked REC valuation methodology ***is the status quo***. The Commission should therefore modify the PD to reject PG&E's pre-2019 banked REC valuation methodology, and instead require PG&E to value the RECs as required by section 366.2(g).

III. THE PD SHOULD BE MODIFIED TO REQUIRE ANY "INTERIM" PRE-2019 BANKED REC VALUATION TO BE CONSISTENT WITH SECTION 366.2(G), COMMISSION PRECEDENT, AND CURRENT PG&E PRACTICE

While the Commission has the record it needs to resolve this issue conclusively here, to the extent the Commission is inclined to address the valuation of pre-2019 banked RECs in a rulemaking, it should continue the status quo which is consistent with section 366.2(g), Commission precedent, and current PG&E practice. The Commission should also direct PG&E to exhaust post-2018 banked RECs before using any pre-2019 banked RECs towards its Minimum Retained RPS requirement. PG&E can meet over 80 percent of its projected 2025 shortfall without using the RECs in controversy in this case. Using post-2018 RECs will minimize PG&E's use of controversial RECs, which will again be the subject of litigation and Commission consideration in a rulemaking.

Finally, the Commission should direct PG&E to track and report not only the pre-2019 banked RECs it uses to meet 2026 compliance, but also any pre-2019 banked RECs it uses to meet ***2025*** compliance. Tracking those RECs will serve the same purpose as tracking the RECs used to meet 2026 compliance requirements. This information will allow any updated guidance from the

[20] D.22-12-044 at Ordering Paragraph (OP) 1; D.23-12-022 at OP 5; D.24-12-038 at COL 1.

Commission regarding the treatment of pre-2019 banked RECs to apply to all pre-2019 banked RECs used for compliance in both 2025 and 2026.

IV. THE COMMISSION SHOULD DIRECT PG&E TO FILE A TIER 2 ADVICE LETTER DETAILING ITS IMPLEMENTATION OF SCE'S INTERIM RA SOD METHOD AND CLARIFY HOW PG&E WILL IMPLEMENT THAT METHODOLOGY

Like PG&E's proposal to change its existing banked REC valuation methodology, PG&E's proposal to modify its existing RA valuation methodology is a policy proposal and, therefore, typically beyond the scope of an ERRA Forecast proceeding. As PG&E acknowledges, the Commission may consider the impacts of SoD on the IOU's ratesetting practices in the PCIA rulemaking.[21] The PD also alludes to a forthcoming "more comprehensive decision on implementation of the SoD methodology."[22] In light of that upcoming decision, the Commission should have excluded PG&E's RA SoD proposal from the scope of this proceeding and directed PG&E to continue implementing its existing approach until the Commission comprehensively addresses the impacts of SoD implementation on the PCIA framework. Requiring parties to litigate a sweeping and highly impactful policy proposal in an expedited ERRA Forecast proceeding—including a revised version of that proposal introduced in mid-October—is highly prejudicial.

Nevertheless, in the interest of narrowing the contested issues in this case, CalCCA does not oppose the PD's conclusion directing PG&E to adopt SCE's SoD methodology on an interim basis while awaiting a more comprehensive decision on the implementation of the SoD methodology. The PD correctly observes PG&E has sufficient information to apply SCE's method. However, in light of PG&E's clear reluctance to implement SCE's method, and PG&E's failure to present the outputs of that method applied to its PCIA portfolio, the Commission should direct

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21 PG&E Opening Brief at 46.
22 PD at 34.

PG&E to file a Tier 2 advice letter within thirty days of the issuance of its final Decision, detailing its implementation of SCE's SoD method. This will allow CalCCA and other interested parties to confirm PG&E has faithfully implemented SCE's method.

Finally, the Commission should make a clarifying edit on page 35. The PD states: "PG&E has sufficient information to apply PG&E's methodology; they would apply their current methodology for calculating the RA sales, unsold and retained RA volumes." The PD's second reference to "PG&E" in that sentence is an error, and the word "their" is susceptible to multiple interpretations. In the interest of clarity, the PD should be revised to say: "PG&E has sufficient information to apply ***SCE's*** methodology; ***PG&E*** would apply ***SCE's*** current methodology for calculating the RA sales, unsold and retained RA volumes."

V. THE COMMISSION SHOULD MEMORIALIZE PG&E'S AGREEMENT THAT DATA CENTER LOAD IN CCA TERRITORY IS PRESUMED TO BE CCA LOAD

CalCCA does not object to the PD's conclusions with respect to PG&E's data center demand forecasts and did not litigate those forecasts in this case. However, CalCCA conducted discovery to evaluate PG&E's assumptions regarding data center load in CCA service territory. PG&E's responses to those discovery requests confirm that PG&E and CalCCA agree data center load located in CCA service territory (and not on a site currently served by an electric service provider) will default to CCA service.[23] The Commission should memorialize this uncontested understanding in a finding in the final Decision.

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[23] *See* Attachment A to CalCCA's Comments on PG&E's Fall Update (PG&E response to CalCCA data request 6.04).

VI. CONCLUSION

For the reasons described in these comments, CalCCA respectfully urges the Commission to adopt the change discussed herein and presented in Appendix A, and to grant any other relief the Commission deems just and reasonable.

Respectfully submitted,

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

December 1, 2025

Counsel to CALIFORNIA COMMUNITY CHOICE ASSOCIATION

APPENDIX A

Pursuant to Rule 14.3(b) of the Commission's Rules of Practice and Procedure, CalCCA provides this Appendix setting forth proposed changes to the *Proposed Decision Approving Pacific Gas and Electric Company's 2026 Energy Resource Recovery Account Related Forecast Revenue Requirement and 2025 Electric Sales Forecast*, including proposed changes to the findings of fact, conclusions of law and ordering paragraphs. CalCCA's proposed revisions appear in underline and strike-through.

Findings of Fact

15. We find it reasonable to adopt ~~PG&E's~~ CalCCA's Pre-2019 Banked RECs methodology on an interim basis for the purpose of this decision.

16. ~~The proposal to address conflicting understandings regarding~~ A permanent methodology for the valuation of Pre-2019 Banked RECs ~~is appropriate for consideration~~ should be established in a rulemaking.

XX. Data center load located in a CCA's service territory that is not on a site currently served by an electric service provider should default to CCA service.

Conclusions of Law

XX. It is reasonable to require PG&E to file a Tier 2 advice letter detailing its implementation of Southern California Edison Company's (SCE) interim Slice-of-Day methodology.

XX. CCAs are the default service providers for data center load that is located in a CCA's service territory and is not on a site currently served by an electric service provider.

Ordering Paragraphs

4. Pacific Gas and Electric Company (PG&E) shall file a Tier 2 advice letter by February 1, 2026 to propose how they will track and report the quantity of pre-2019 banked RECs used to meet 2025 or 2026 compliance and the year those RECs were generated. The advice letter shall explain how PG&E intends to track the quantity and generation year of all Pre-2019 banked RECs it will use to meet 2025 or 2026 compliance requirements through September 30, 2026. The advice letter shall also explain how PG&E intends to forecast how many and which RECs PG&E intends to use for bundled customer compliance from October 1, 2026 through December 30, 2026.

XX. PG&E shall file a Tier 2 advice letter within thirty days of the issuance of this Decision detailing its implementation of Southern California Edison Company's (SCE) interim Slice-of-Day methodology, including the results of that methodology on the valuation of PG&E's Resource Adequacy (RA) resources and on Power Charge Indifference Adjustment (PCIA) rates.

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

Order Instituting Rulemaking to Enhance Demand Response in California.	R.25-09-004

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON THE ORDER INSTITUTING RULEMAKING TO ENHANCE DEMAND RESPONSE IN CALIFORNIA

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

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

December 1, 2025

TABLE OF CONTENTS

SUMMARY OF RECOMMENDATIONS[1]

In response to Opening Comments to the OIR, CalCCA recommends that the Commission:

- Reject SCE's proposal to consider dynamic rate data systems and processes only in dynamic rate applications to ensure needed updates are made to enable a level playing field for data access;
- Adopt 350 Bay Area's recommendation to consider how deployment of DR resources can be incorporated into state energy planning processes, including the IEPR, IRP, and transmission planning, to ensure outcomes from this proceeding are actionable;
- Consider topics related to customer experience with DR programs and resources as recommended by Olivine, Vote Solar, PG&E, SDG&E, and SCE to address customer barriers to adoption;
- Adopt SCE's recommendation to address rules to enhance and target load flexibility to harmonize the benefits and limitations of load flexibility, DR resources, and dynamic rates;
- Adopt PG&E's recommendation to develop a flexible policy framework that enables virtual power plants to provide more grid services;
- Coordinate with the CAISO's DDEMI and the Commission's RA proceeding as recommended by several parties to align outcomes between the future of DR resources and California's grid needs; and
- Adopt SCE's recommendation to hold workshops to clarify Energy Division Staff's Proposed DR Guiding Principles, given the high volume of parties recommending modifications.

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

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Enhance Demand Response in California.	R.25-09-004

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON THE ORDER INSTITUTING RULEMAKING TO ENHANCE DEMAND RESPONSE IN CALIFORNIA

The California Community Choice Association[2] (CalCCA) submits these reply comments pursuant to Rule 6.2 of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure,[3] in response to party Opening Comments on the *Order Instituting Rulemaking to Enhance Demand Response in California*[4] (OIR), issued September 20, 2025, and the directives therein.[5]

I. INTRODUCTION

The strong interest of stakeholders in this proceeding is demonstrated by the 35 sets of Opening Comments filed in response to the OIR. This level of engagement, representing many interests, reiterates the need for the Commission to craft the scope of this proceeding carefully, ensuring that parties have an adequate opportunity to discuss and review the broad range of

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

4 *Order Instituting Rulemaking to Enhance Demand Response in California*, Rulemaking (R.) 25-09-004 (issued Sept. 29, 2025).

5 All references to Opening Comments refer to the Opening Comments on the OIR filed in this docket on November 13, 2025.

proposals. CalCCA continues to support its scoping recommendations set forth in its Opening Comments. These Reply Comments address the numerous additional scoping items recommended by parties, aiming to optimize the scope of this proceeding for improving demand response (DR) and load shifting resources.

As set forth below, CalCCA recommends that the Commission:

- Reject Southern California Edison Company's (SCE) proposal to consider dynamic rate data systems and processes only in dynamic rate applications to ensure needed updates are made to enable a level playing field for data access and to enable all load-serving entities to participate in dynamic pricing;

- Adopt 350 Bay Area's recommendation to consider how deployment of DR resources can be incorporated into state energy planning processes, including the California Energy Commission's (CEC) Integrated Energy Policy Report (IEPR), the Commission's Integrated Resource Planning (IRP) and Resource Adequacy (RA) proceedings, and the Commission's and the California Independent System Operator's (CAISO) transmission planning, to ensure outcomes from this proceeding are actionable;

- Consider issues regarding customer experience with DR programs and resources to address customer barriers to adoption as recommended by Olivine, Inc. (Olivine), Vote Solar, Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and SCE;

- Adopt SCE's recommendation to address rules to enable harmonizing the benefits and limitations of load flexibility, DR resources, and dynamic rates;

- Adopt PG&E's recommendation to develop a flexible policy framework that enables virtual power plants (VPP) to provide more grid services;

- Ensure coordination with CAISO's Demand and Distributed Energy Market Integration (DDEMI) initiative and the Commission's RA proceeding as recommended by several parties to align outcomes between the future of DR resources and California's grid needs; and

- Adopt SCE's recommendation to hold workshops to clarify Energy Division Staff's Proposed DR Guiding Principles, given the high volume of parties recommending modifications.

II. SCE'S PROPOSAL TO CONSIDER DYNAMIC RATE DATA SYSTEMS AND PROCESSES ONLY IN DYNAMIC RATE APPLICATIONS SHOULD BE REJECTED

The Commission should reject SCE's recommendation to only consider updates to investor-owned utility (IOU) dynamic rate systems and processes in individual IOU dynamic rate applications. SCE distinguishes statewide systems and processes from those related to individual IOU dynamic rate proposals, and recommends that this proceeding should only consider statewide systems rather than individual IOU systems to enable dynamic rates.[6] SCE states that it "is concerned that the implementation of dynamic rates will be delayed if the DR Rulemaking considers both the systems and processes necessary to implement dynamic proposals and the broader statewide [CEC Load Management Standards (LMS)]-related systems together."[7] SCE's recommendation to disconnect IOU and statewide dynamic pricing systems and processes should be rejected because of the need for the systems to interact with one another.

Ignoring the needed updates to dynamic rate-related data systems in this proceeding will directly impede the broader implementation of dynamic rates and the requirements in the CEC's LMS for IOUs, large community choice aggregators (CCA), and large publicly owned utilities regarding rates and programs related to dynamic prices. As CalCCA outlined in its Opening Comments, Decision (D.) 25-08-049 closed the Demand Flexibility proceeding without addressing items scoped into that proceeding relating to systems and processes necessary to enable access to dynamic rates for both bundled *and unbundled* customers.[8] The Commission

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6 *See* SCE Opening Comments, at 16 (recommending considering statewide data systems for dynamic rates in this proceeding and leaving consideration of individual IOU dynamic rate systems and processes to specific IOU application proceedings).

7 *Ibid.*; *see also* 20 Cal. Code of Regulations (CCR) §§ 1621, 1623, 1623.1 (LMS Regulations).

8 D.25-08-049, *Decision Adopting Guidelines for Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company on Demand Flexibility Rate Design Proposals,* R.22-07-005 (Aug. 28, 2025); *see also* CalCCA Opening Comments, at 8 (stating that the vital

recognized it failed to resolve this scoped item, but stated that it *"will address these issues in one or more new rulemakings."*[9] A little over two weeks later, the Commission opened this DR proceeding, with preliminary scoping item 3 to consider "standardized data systems, communication protocols, and data transfer processes . . . to support demand response initiatives, *including dynamic rates."*[10] CalCCA originally objected to closing the Demand Flexibility proceeding without addressing the necessary data systems and processes to allow all customers to access dynamic rates.[11] However, with the opening of this new, broader Demand Response proceeding, CalCCA now supports the Commission taking this issue up in this proceeding.

This proceeding is the ideal venue for discussing data access and data quality standards for both new and existing data systems and processes, as well as cost responsibility for those systems, even if IOUs must implement those standards through a separate application for cost recovery. The DR landscape will benefit from a level playing field in terms of data access, particularly for CCAs who serve a significant proportion of the load in California and many of whom have programs for their communities that will help spur the adoption of DR resources. If necessary, the Commission can incorporate a separate ratesetting track for this proceeding to address cost recovery for Commission and CEC required data systems and processes for dynamic pricing and LMS.

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data access issues CCAs have raised were not addressed in the Demand Flexibility proceeding before it closed).

9 D.25-08-049, at 13 (emphasis added).

10 OIR, at 10.

11 *See California Community Choice Association's Comments on the Proposed Decision,* R.22-07-005 (Aug. 14, 2025) (objecting to the Commission prematurely closing R.22-07-005 without addressing scoped issues to allow unbundled customers to participate in dynamic pricing: "While the [Proposed Decision] does address unbundled customers and dynamic pricing rate design, it fails to resolve scoped systems and processes issues, including CCA data access, and cost responsibility surrounding those systems and processes.").

SCE's argument that this proceeding's scope "is not focused enough to consider the specific systems needed to implement each IOU's dynamic rate proposal"[12] should also be rejected. Notwithstanding that the scope is currently being defined, SCE's argument ignores the Commission's plain interest, as demonstrated by preliminary scoping item 3 from the OIR,[13] in establishing a robust ecosystem of DR systems and processes, including those related to dynamic rates. The OIR recognizes that to implement the wide range of DR resources effectively, updates or amendments may be needed to existing systems and processes, regardless of how cost recovery will occur. Feedback from stakeholders and the Commission about IOU dynamic rate-related systems is valuable, and this proceeding brings together a wider range of parties than specific IOU applications. Additionally, simply because a proceeding has multiple priorities does not mean the Commission and parties cannot adequately address specific priorities. For these reasons, the Commission should reject SCE's recommendation to exclude consideration of dynamic rate data systems and processes from the scope of this proceeding.

III. THE CONSIDERATION OF HOW DR RESOURCES CAN BE INCORPORATED INTO STATE CORE PLANNING PROCESSES SHOULD BE ADDED TO THE PROCEEDING SCOPE

The Commission should adopt 350 Bay Area's recommendation to consider how the deployment of DR resources can be incorporated into planning processes such as the CEC'S IEPR, the CPUC's IRP and RA proceedings, and CPUC and CAISO transmission planning.[14] While the OIR recognizes the need to coordinate with other Commission proceedings given

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12 SCE Opening Comments, at 17.

13 *See* DR OIR, at 10 ("What standardized data systems, communication protocols, and data transfer processes should the Commission adopt or amend to support demand response initiatives, including dynamic rates?").

14 *See* 350 Bay Area Opening Comments, at 5 (recommending the need to incorporate deployment of cost-effective DR into the state's core energy planning processes, including IEPR, IRP, and transmission planning).

overlapping topic areas,[15] the outcomes from this proceeding may require integration into larger state planning processes for benefits to be realized. For example, if certain valuation methodologies or frameworks for DR are modified through this proceeding that impact RA planning and procurement, then considering how to integrate those changes into larger, relevant state planning processes will ensure effective implementation of those changes. Failing to incorporate changes developed in this proceeding into larger planning processes could delay determining necessary logistics, which may also take time to implement (*e.g.*, waiting for the next planning cycle or annual report). While the Commission should not rush through important discussions in this proceeding, it should recognize potential impacts that outcomes from this proceeding can have on other proceedings, initiatives, and goals, including the state's 7,000-megawatt load shift goal for 2030.[16]

IV. CUSTOMER ACCESS TO AND EXPERIENCE WITH DR PROGRAMS AND RESOURCES SHOULD BE CONSIDERED IN THIS PROCEEDING AS PROPOSED BY MULTIPLE PARTIES

The Commission should include in the scope of this proceeding a discussion of customer-related topics, such as accessibility, incentives, environmental justice, and customer confusion. Olivine, Vote Solar, PG&E, SDG&E, and SCE recommend that the Commission consider the following customer-related topics related to the deployment of DR:

- *Customer experience improvements:* Olivine states that "[i]mprovements to the current customer experience, such as streamlined authorization processes, similar processes, and standard [service-level agreements] could have a significant impact on customer participation and administrative efforts.[17]

15 *See* OIR, at 10 (asking whether any specific issues previously addressed or underway in other Commission proceedings require coordination with this rulemaking).

16 *See* CEC Docket 21-ESR-01, *SB 846 Load Shift Goal Commission Report* (May 26, 2023).

17 Olivine Opening Comments, at 6-7.

- *Environmental justice:* Vote Solar recommends the Commission include an environmental justice framework in this proceeding to help evaluate how energy infrastructure impacts disadvantaged communities and advance the locational specificity of DR resources.[18]

- *DER technology incentive requirements:* PG&E recommends the Commission "explore opportunities to enhance DER technology incentive requirements that streamline customer experience and increase program benefits."[19]

- *Technical efficiencies:* SDG&E states that "[t]he customer's enrollment in any program should be with a minimum of technical hindrance," and that interoperability of devices would enable greater customer control.[20]

- *Clarity on DR programs to prevent customer confusion:* SCE recommends that this proceeding establish consistent rules for the definition and application of "qualified" DR programs to minimize customer confusion.[21]

The various issues demonstrate the many considerations this proceeding should discuss from a customer perspective. Ultimately, the success of DR resources depends on customers being aware of, learning about, signing up for, actively participating in, and realizing benefits from programs and initiatives that this proceeding will shape. Considering these customer perspectives while examining changing or establishing requirements for DR resources will increase the likelihood of success and ensure customer needs are met while also contributing to grid benefits. Additionally, in the case of SCE's recommendation on "qualified" DR programs, particularly as related to the Self-Generation Incentive Program (SGIP), considering customer experiences in this proceeding will help minimize confusion and enhance customer choice of programs that satisfy their needs. Therefore, the Commission should consider party

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18 Vote Solar Opening Comments, at 5 (describing the unfair distribution of burdens and benefits of energy infrastructure and the opportunity to address that through DR resource deployment).

19 PG&E Opening Comments, at A-13.

20 SDG&E Opening Comments, at 8.

21 SCE Opening Comments, at 7-8 (describing the impacts to customers if changes are made to enrollment requirements, such as SGIP's requirement to be enrolled in a "qualified" DR program).

recommendations regarding customer experiences and customer access to DR resources and programs to minimize barriers to customer adoption.

V. SCE'S RECOMMENDATION TO ADDRESS RULES TO ENHANCE AND TARGET LOAD FLEXIBILITY SHOULD BE ADOPTED

The Commission should include SCE's recommendation to enhance and target load flexibility in the scope of this proceeding. SCE observes:

> Largely absent from the existing DR rulesets, and not included in the proposed scope in this Rulemaking, is what policies need to be considered to better integrate and coordinate managed device load flexibility programs for local distribution-level reliability, affordability, and grid readiness alongside DR.[22]

This comment from SCE bears similarity in theme to PG&E's recommendation to expand the scope and change the name of this proceeding to "Load Management."[23] SCE and PG&E identify the convergence of technologies, program designs, and frameworks that provide load flexibility, which have historically developed independently of each other. SCE even points out that distribution-focused load flexibility programs provide direct load control capabilities that dynamic rates and DR programs cannot.[24] With this convergence, the Commission, along with stakeholders, should take stock and consider how DR resources and load management strategies affect each other, and where those resources and strategies should be implemented. All the benefits and limitations of load flexibility, DR resources, and dynamic rates should be considered in one place so they can be optimized together. Therefore, the Commission should adopt SCE's recommendation to address rules to enhance and target load flexibility.

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22 *Id.*, at 18.

23 PG&E Opening Comments, at A-4.

24 *See* SCE Opening Comments, at 19 (describing what load flexibility programs provide that dynamic rates and DR programs do not provide).

VI. THIS PROCEEDING SHOULD INCLUDE PG&E'S RECOMMENDATION TO DEVELOP A FLEXIBLE POLICY FRAMEWORK THAT ENABLES VPPS TO PROVIDE MORE GRID SERVICES

The Commission should adopt PG&E's recommendation to include a flexible policy framework for VPPs in the scope of this proceeding. PG&E asserts that the current policy framework and processes "hinder the future-proofing of California's grid by primarily limiting DR resources to providing peak load-shedding services."[25] PG&E's view of the future of VPPs is that they provide more than peak load-shedding services, including continuous load shaping.[26] Both load-shedding and load-shaping services provide grid benefits in their own ways, and both will be necessary to optimize California's grid for a clean energy future. Development of a policy framework that further enables VPPs is an excellent example of an outcome that can be informed by existing preliminary scoping items, such as valuation of methodologies and evaluation metrics, and CAISO market integration topics.[27] When discussing topics like valuation methodologies or market integration frameworks, the Commission and stakeholders should have clear end goals or work products in mind. Planning for those outcomes through the future DR Scoping Ruling will establish a shared goal for everyone. Therefore, the Commission should adopt PG&E's recommendation to develop a flexible policy framework that enables VPPs to provide more grid services in this proceeding.

VII. THIS PROCEEDING SHOULD BE COORDINATED WITH THE CAISO'S DDEMI INITIATIVE AND THE COMMISSION'S RA PROCEEDING, AS RECOMMENDED BY SEVERAL PARTIES

The Commission should coordinate the DR proceeding with the CAISO's DDEMI initiative and the RA proceeding, as recommended by California Efficiency + Demand

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25 PG&E Opening Comments, at A-6.
26 *Ibid*.
27 *See* OIR, at 9 (Preliminary Scoping Items 2.b. and 2.c.).

Management Council (CEDMC), PG&E, and SCE.[28] CalCCA agrees with CEDMC that "[i]t is critical to have good coordination between the Commission and the CAISO where both entities have jurisdiction over certain pieces of related issues, including DR."[29]

In Opening Comments to the RA OIR, several parties, including CalCCA, recommended the Commission address RA issues related to DR.[30] As PG&E states, "[b]ecause there are likely to be DR implementation issues that are not within the purview of the RA OIR, work on this issue will need to be coordinated with the CAISO's [DDEMI initiative and the DR OIR]."[31] The Commission should coordinate this proceeding with the CAISO's DDEMI initiative and the RA proceeding to: (1) enhance SOD RA accounting for DR; and (2) develop policy related to behind-the-meter (BTM) exports.

A. CalCCA Supports Enhancing SOD RA Accounting for DR in this Proceeding, as Recommended by CEDMC, EnergyHub, Olivine, and SCE

The Commission should enhance the SOD RA accounting methodology for DR in this proceeding to allow DR to be shown beyond the availability assessment hours (AAH), as recommended by CEDMC, EnergyHub, Olivine, and SCE.[32] Current RA rules allow DR resources to be shown only during the AAHs. As stated by SCE, "[t]his means that DR cannot reduce a [LSE's] RA obligation outside of the AAHs, even if a DR resource can provide capacity outside of the AAH window."[33]

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28 *See* CEDMC Opening Comments, at 5; PG&E Opening Comments, at A-13; and SCE Opening Comments, at 20.

29 CEDMC Opening Comments, at 5.

30 *See California Community Choice Association's Comments on the Order Instituting Rulemaking*, R.25-10-003 (Nov. 4, 2025), at 11; and *California Community Choice Association's Reply Comments on the Order Instituting Rulemaking*, R.25-10-003 (Nov. 14, 2025) (CalCCA OIR Reply Comments), at 4-5.

31 PG&E Opening Comments, at A-13.

32 *See* CEDMC Opening Comments, at 7; EnergyHub Opening Comments, at 10; Olivine Opening Comments, at 5; and SCE Opening Comments, at 20.

33 SCE Opening Comments, at 20.

The SOD framework made significant changes to the RA program by requiring LSEs to show capacity for all 24 hours of the worst day of the month. Constraining DR RA showings to the AAHs could potentially ignore the reliability value that DR resources could provide under the SOD program. As stated by Olivine, DR should be able to provide RA in SOD hours "… where they can demonstrate availability and performance capability."[34] The Commission should therefore consider enhancements to SOD RA accounting for DR in the scope of this proceeding and/or in the RA proceeding.

B. CalCCA Supports Including BTM Exports in Scope, as Recommended by PG&E, CEDMC, and CESA

CalCCA agrees with PG&E, CEDMC, and CESA that the Commission should coordinate with the CAISO to develop policy related to BTM exports, including reviewing the Load Impact Protocols.[35] In the CAISO's ongoing DDEMI stakeholder initiative, the CAISO is considering a modified Proxy Demand Resource model to improve the ability of BTM resources to participate in wholesale markets by crediting net exports and revising metering requirements.[36] As recommended in CalCCA's Opening Comments to the RA OIR in proceeding R.25-10-003, the Commission should develop policy related to BTM exports, including the development of a qualifying capacity (QC) methodology.[37]

In developing a QC methodology for BTM exports, there are several key questions that must be addressed in coordination with the CAISO. This proceeding and/or the recently opened RA proceeding should address these questions in alignment with the CAISO's efforts. As the

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[34] Olivine Opening Comments, at 5.

[35] *See* CEDMC Opening Comments, at 6; PG&E Opening Comments, at A-13; CESA Opening Comments, at 3.

[36] Sunrun, Tesla, Inc., & California Solar & Storage Association (CalSSA), *Behind-the-Meter Storage Participation in Wholesale Markets, CAISO DDEMI Working Group* (Sept. 9, 2025).

[37] *See* CalCCA OIR Reply Comments, at 4-5.

CAISO develops its market and deliverability rules related to BTM exports, the Commission should simultaneously develop the necessary rules within its jurisdiction, including the development of a QC methodology. This should include reviewing the Commission's Load Impact Protocols, as recommended by CESA, to ensure the protocols are fit for measuring BTM storage resources.[38]

VIII. SCE'S RECOMMENDATION TO HOLD WORKSHOPS TO CLARIFY THE PROPOSED DR GUIDING PRINCIPLES SHOULD BE ADOPTED

The Commission should hold one or more workshops to clarify the proposed DR Guiding Principles, as SCE recommends. Twenty-two parties recommended modifications to the DR Guiding Principles proposed in the Energy Division Staff Proposal attached to the OIR.[39] This level of engagement from this many parties suggests the Proposed DR Guiding Principles need more room for discussion before the Commission adopts them. One or more workshops will allow Energy Division to ensure parties understand the intent and wording of the Proposed DR Guiding Principles and will allow parties to get clear answers to clarifying questions as well as discuss differing opinions to reach a consensus. Since DR Guiding Principles underpin the central issues in this proceeding, taking time to ensure robust engagement by all stakeholders is extremely important. Therefore, the Commission should adopt SCE's recommendation to hold workshops to clarify the Proposed DR Guiding Principles.

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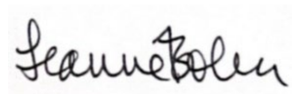
[38] *See* CESA Opening Comments, at 3.

[39] Opening Comments of CalCCA, PG&E, SDG&E, SCE, CEDMC, LEAP, Voltus, The Utility Reform Network, Enchanted Rock, LLC, Vote Solar, Olivine, California Large Energy Consumers Association, the Joint Regional Energy Networks, Cohen Ventures, Inc., Small Business Utility Advocates, CPower Energy LLC, The Mobility House, CAISO, EnergyHub, 350 Bay Area, Renew Home, and CalSSA all recommend modifications to the Proposed DR Guiding Principles.

IX. CONCLUSION

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

Respectfully submitted,



Leanne Bober,
Director of Regulatory Affairs and Deputy General Counsel

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

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

Order Instituting Rulemaking to Establish a Framework and Processes for Assessing the Affordability of Utility Service.	R.18-07-006

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION UPDATING THE AFFORDABILITY FRAMEWORK AND CLOSING PROCEEDING

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

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

December 3, 2025

TABLE OF CONTENTS

TABLE OF AUTHORITIES

Other Authorities

California Public Utilities Commission Decisions

California Public Utilities Commission Proceedings

California Public Utilities Commission Rulings

California Public Utilities Commission Rules of Practice and Procedure

SUMMARY OF RECOMMENDATIONS[1]

CalCCA makes the following recommendations to increase the effectiveness of the affordability metrics and maintain a clear path for addressing the affordability of electric rates:

- Reject the Proposed Decision's narrower requirement for IOUs to submit affordability metrics only in GRCs, which reduces the usefulness and comprehensiveness of the affordability metrics;
- Expand the criteria for submission of the affordability metrics to any Commission proceeding, which could increase rates to provide a better view of all cost increases, not just those proposed by IOUs;
- In the event the Commission adopts the narrower criteria for affordability metric submission, create a process for parties to request submission of the affordability metrics and require the Commission to grant the request or explain why the affordability metrics would not be helpful in that proceeding;
- Adopt the Proposed Decision's requirement for providing additional contextual data alongside affordability metrics to enhance transparency and accountability; and
- Provide more concrete next steps for how the Commission will pursue its strategies to contain costs and increase the affordability of electric bills.

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

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Establish a Framework and Processes for Assessing the Affordability of Utility Service.	R.18-07-006

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION UPDATING THE AFFORDABILITY FRAMEWORK AND CLOSING PROCEEDING

The California Community Choice Association[2] (CalCCA) submits these comments pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure[3] on the proposed *Decision Updating the Affordability Framework and Closing Proceeding*[4] (Proposed Decision), dated November 13, 2025.

I. INTRODUCTION

California has the second-highest residential electricity rates in the United States, at almost double the national average.[5] Unprecedented events like extreme wildfires and the

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

[4] Proposed *Decision Updating the Affordability Framework and Closing Proceeding*, Rulemaking (R) 18-07-006 (Nov. 13, 2025): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M586/K598/586598168.PDF.

[5] *National Electricity Rates*, Power Outage (accessed Nov. 26, 2025): https://poweroutage.us/electricity-rates.

COVID-19 pandemic have resulted in the investor-owned utilities (IOU) requesting to spend even more to ensure California's grid remains safe and reliable, while meeting state clean energy goals. The Commission's role is to review those and other requests alongside the perspective of stakeholders and determine the reasonableness of cost increases. More than seven years ago, the Commission initiated this rulemaking to establish a framework to make utility service more affordable. Phases One and Two of this proceeding created and implemented the affordability metrics, and the Commission scoped in a third phase to consider strategies to mitigate energy rate increases.[6] To launch this third phase, the Commission hosted a two-day En Banc at which stakeholders, utilities, ratepayer advocates, academics, and industry experts presented a variety of strategies to address affordability in the short- and long-term.

Following the En Banc, Phase Three has largely been inactive. While other Commission proceedings considered some of the En Banc proposals (*e.g.,* income-graduated fixed charge and dynamic rates were considered in the Demand Flexibility proceeding, R.22-07-005, this proceeding remained quiet other than allowing a venue for comments on annual Senate Bill 695 Reports related to affordability. The most recent ruling requesting party feedback was two years ago, and since August 2022, the only Commission decisions issued have been procedural, not substantive.[7] Now, the Proposed Decision presents a mix of directives that will have positive and negative effects on the Commission's affordability framework and concludes with vague descriptions of how the Commission will continue to act on its responsibility to contain costs. CalCCA appreciates the Commission's attention to affordability and the difficulty of balancing

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6 *Assigned Commissioner's Fourth Amended Scoping Memo and Ruling*, R.18-07-006 (Sept. 15, 2021), at 7 (establishing a third phase of R.18-07-006 to consider strategies to mitigate energy rate increases): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M407/K793/407793995.PDF.

7 D.22-08-023 is the most recent Commission decision with substantive direction for parties until the Proposed Decision. All other decisions have either ordered extension of the statutory deadline or ruled on intervenor compensation claims.

priorities, but this does not absolve the Commission of its responsibility to work with stakeholders to continue to develop solutions.

First, the Proposed Decision narrows the criteria for submission of the affordability metrics to only IOU general rate cases (GRC).[8] This directly inhibits the benefits of transparency, accountability, and long-term tracking that the affordability metrics provide. The Proposed Decision asserts that narrowing the criteria will allow for more in-depth analysis of the affordability metrics. However, the transparency that the affordability metrics provide comes in significant part from the range of applications and proceedings that impact affordability, not the depth of the analysis once they are presented. Fewer submissions of the affordability metrics will only result in less visibility into the impacts on rates of cost recovery requests.

Additionally, the Proposed Decision claims that because no party submitted testimony using affordability metrics in response to San Diego Gas & Electric Company's (SDG&E) Phase Two GRC Application (A.) 23-01-008, the parties do not find the affordability metrics useful outside of Phase One GRCs.[9] This ignores the fact that the affordability metrics SDG&E submitted in testimony all demonstrated that the Application would slightly decrease residential rates, meaning its impacts were positive.[10] Rather than demonstrating a lack of usefulness, this demonstrates how valuable the metrics can be for focusing on other issues when impacts to affordability are not a concern. The Commission should reject this aspect of the Proposed Decision and instead *expand* the criteria for submission of the affordability metrics to any Commission proceeding that considers proposals that could increase costs. If the Commission does adopt the Proposed Decision's narrowing of criteria for submission, it should at least

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8 *See* Proposed Decision, at 68-69, Ordering Paragraph (OP) 1.

9 *Id.* at 35-36.

10 *Prepared Testimony of Rachelle R. Baez on Behalf of San Diego Gas & Electric Company*, A.23-01-008 (Jan. 17, 2023), at RRB-4 through RRB-14, Tables RRB-1 through RRB-12.

establish a process to allow parties to formally request use of the affordability metrics. This should be accompanied by a requirement for the assigned Commissioner or Administrative Law Judge (ALJ) to respond to the request by either requiring the submission of the affordability metrics or denying the request with an explanation as to why.

Second, the Proposed Decision directs IOUs to provide more contextual data alongside affordability metrics when metrics are submitted. In contrast to narrowing the criteria for submission, this takes a step towards transparency and accountability.[11] It allows an easier comparison of IOU cost recovery requests to other cost growth indicators like inflation, which empowers decision-makers to balance competing priorities in a more informed way. The Commission should adopt this aspect of the Proposed Decision.

Finally, the Proposed Decision concludes the discussion of issues with a very brief narrative on next steps and how the Commission will continue to address affordability. The most solid recommendations come from the Commission's response to Governor Newsom's Executive Order N-5-24:[12] (1) control growth in utility spending; (2) find additional funding sources for wildfire mitigation, rooftop solar cost-shift, and future cost-shifts, low-income assistance, non-cost-effective programs; and (3) reduce rate inequities that exempt advantaged customers from paying fixed costs.[13] CalCCA supports these strategies, but the Proposed Decision falls short of discussing *how* the Commission will explore these strategies further, where that exploration might occur, and when parties can expect to engage on these strategies. Given that the Proposed Decision closes this proceeding, the Commission should provide more

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11 Proposed Decision, at 69, OP 1.

12 EXECUTIVE ORDER N-5-24 (Oct. 30, 2024): https://www.gov.ca.gov/wp-content/uploads/2024/10/energy-EO-10-30-24.pdf.

13 Proposed Decision, at 62.

concrete next steps for stakeholders and the public. Without proper venues, the Commission cannot make meaningful progress on any strategies to address affordability and contain costs.

CalCCA makes the following recommendations to increase the effectiveness of the affordability metrics and maintain a clear path for addressing the affordability of electric rates:

- Reject the Proposed Decision's requirement for IOUs to submit affordability metrics only in GRCs, which reduces the usefulness and comprehensiveness of the affordability metrics;
- Expand the criteria for submission of the affordability metrics to any Commission proceeding that could increase rates to provide a better view of all cost increases, not just those proposed by IOUs;
- In the event the Commission adopts the narrower criteria for affordability metric submission, create a process for parties to request submission of the affordability metrics and require the Commission to grant the request or explain why the affordability metrics would not be helpful in that proceeding;
- Adopt the Proposed Decision's requirement for providing additional contextual data alongside affordability metrics to enhance transparency and accountability; and
- Provide more concrete next steps for how the Commission will pursue its strategies to contain costs and increase the affordability of electric bills.

II. THE COMMISSION SHOULD REJECT THE PROPOSED DECISION'S MODIFICATION TO ONLY REQUIRE USE OF THE AFFORDABILITY METRICS IN GENERAL RATE CASES

The PD's modification to only require the affordability metrics in GRCs dramatically stunts the transparency and accountability they provide and should be rejected. The PD directs the IOUs to provide affordability metrics in Phase One GRCs in which the revenue increase is estimated to exceed one percent of currently authorized revenues.[14] This is a departure from Decision (D.) 22-08-023,[15] which originally implemented the affordability metrics and required

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14 *Id.* at 68-69, OP 1.

15 D.22-08-023, *Decision Implementing the Affordability Metrics*, R.18-07-006 (Aug. 4, 2022), at 84, OP 5: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M496/K428/496428621.PDF.

them in "any initial filing in any proceeding" with a revenue increase estimated to exceed one percent of currently authorized revenues.[16] The PD asserts that requiring fewer applications with metrics, along with additional context directed by the PD, is intended to generate more useful analysis supporting affordability.[17] This well-intentioned logic fails for several reasons, as discussed below: (1) the usefulness of the affordability metrics is not in the depth of the analysis, but instead in transparency, accountability, and comprehensive long-term tracking across proceedings; and (2) the evidence provided that stakeholders do not find the affordability metrics is flawed and does not suggest a lack of usefulness.

A. The Affordability Metrics Are Useful Because They Provide Transparency, Accountability, and Tracking of Affordability Impacts Over Time and Across Proceedings

The usefulness of the affordability metrics arises from the transparency and accountability they provide regarding the impacts of IOU cost recovery requests on customer bills and the collective snapshots over time of those impacts. The depth of analysis of the affordability metrics after an IOU has submitted them will not contribute to these goals. It may provide certain insights to whoever decides to perform the analysis, but once an IOU has provided the metrics accurately, the affordability metrics fulfill their purpose. The transparency the affordability metrics provide arises in significant part from the range of applications and proceedings that impact affordability, not the depth of the analysis once they are presented. The Commission adopted the affordability metrics in D.20-07-032, which states that the metrics will "allow Commission decision-makers and stakeholders to consider the relative impact on the

16 D.22-08-023.

17 *See* Proposed Decision, at 35.

affordability metrics of proposals before the Commission."[18] For the Commission and stakeholders to consider the impacts of proposals on affordability, the affordability metrics must, at a bare minimum, be submitted. The Proposed Decision removes opportunities for consideration by narrowing the number of times IOUs submit the affordability metrics. This reduces transparency for any proceeding or application other than Phase One GRCs in which an IOU is making an impactful cost recovery request.

It also reduces accountability because limiting the submission of affordability metrics to GRCs means that IOUs will no longer need to show how proposals outside of GRCs impact customer rates, especially for vulnerable, low-income customers. The reasonableness of proposals is directly tied to the customer rate impacts that stem from those proposals. The Commission cannot be fully accountable for verifying the reasonableness of an IOU cost recovery proposal without knowing the impacts to customers.

Finally, each submission of the affordability metrics marks a moment in time that can be referenced in the future to track how affordability fluctuates over time. This allows the Commission and the public to better understand how IOU cost recovery requests influence customer bills in the long term. Long-term trends for procurement, programming, capital planning, and operations that increase costs to ratepayers will help inform Commission decision-makers via consistent submission of the affordability metrics.

B. Absence of Affordability Metrics in Testimony Submitted to A.23-01-008 Is Not Evidence to Suggest a Lack of Usefulness

The absence of party testimony using affordability metrics submitted to SDG&E's Phase Two GRC application A.23-01-008 does not suggest the affordability metrics are not useful to

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18 D.20-07-032, *Decision Adopting Metrics and Methodologies for Assessing the Relative Affordability of Utility Service*, R.18-07-006 (July 16, 2020), at 2-3: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M344/K049/344049206.PDF.

parties. Decision 22-08-023 directs SDG&E to include the affordability metrics in its 2025 Test Year Phase Two GRC application (Application),[19] and SDG&E complied. The Proposed Decision points out that no party submitted testimony in A.23-01-008 that included the affordability metrics and then asserts that this lack of utilization of the affordability metrics demonstrates that there is not a need for affordability metrics outside of Phase One GRCs.[20] This logic ignores a key detail about SDG&E's Phase Two GRC A.23-01-008: the affordability metrics included as chapter nine of testimony demonstrate that residential electric rates would be slightly *more* affordable. All affordability metrics displayed in SDG&E's testimony showed negative values, meaning the proposed changes in the application would reduce residential bills.[21] This fact is the likeliest explanation as to why intervenors did not include affordability metrics in testimony: there were no residential affordability issues with the Application that warranted an alternative proposal using the affordability metrics. Rather than demonstrating a lack of usefulness, this demonstrates how valuable the metrics can be for focusing on other issues when impacts to affordability are not a concern. Concluding that parties are not interested in the affordability metrics outside of Phase One GRCs based on this outcome from SDG&E's Application is unreasonable.

C. The Commission Should Expand the Criteria for Including Affordability Metrics in Individual Proceedings

Rather than narrow the criteria, the Commission should expand the criteria for including the affordability metrics in individual proceedings. As CalCCA has argued multiple times, there is a need for the Commission to integrate the affordability metrics into non-ratesetting

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19 D.22-08-023, at 85, OP 7.

20 *See* Proposed Decision, at 35-36.

21 *Prepared Testimony of Rachelle R. Baez on Behalf of San Diego Gas & Electric Company*, A.23-01-008 (Jan. 17, 2023), at RRB-4 through RRB-14, Tables RRB-1 through RRB-12.

proceedings that may have impacts on rates.[22] IOU cost recovery applications are not the only proceedings that have a significant impact on customer rates. Proceedings that affect rate design and cost allocation (*e.g.*, dynamic rates, the Power Charge Indifference Adjustment), resource procurement (*e.g.*, Resource Adequacy, Integrated Resource Planning), or infrastructure (*e.g.,* Energization) are primary examples of venues that would benefit from the insights the affordability metrics provide. Commission motivations other than affordability may need to take priority over customer rates to meet external requirements or ensure a safe and reliable grid. Still, the impacts on customer rates should be considered during the decision-making process to ensure the Commission can consider all the impacts of new or amended policies.

D. If the Commission Only Requires Affordability Metrics in GRCs, then it Should Adopt a Process to Allow Parties to Request the Affordability Metrics on the Record

If the Commission does adopt the Proposed Decision's modifications to narrow the criteria for submitting the affordability metrics, then it should create a process to allow parties to formally request submission of the affordability metrics. The Proposed Decision states that it will not require affordability metrics in proceedings other than GRCs unless directed by the assigned Commissioner or ALJ.[23] Though CalCCA supports submission of affordability metrics in ***any*** application or rulemaking that could increase customer rates, providing the Commissioner or ALJ discretion maintains some degree of flexibility for the affordability metrics to be submitted. Intervenors and parties to various applications and proceedings possess perspectives and

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22 *California Community Choice Association's Comments on Assigned Commissioner's Ruling Seeking Annual Feedback on the Implementation of the Affordability Framework*, R.18-07-006 (Jan. 25, 2024), at 7: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M523/K993/523993187.PDF; *California Community Choice Association's Comments on Assigned Commissioner's and Assigned Administrative Law Judge's Ruling Inviting Comments on Staff Proposal on Implementation of Affordability Metrics*, R.18-07-006 (Jan 10, 2022), at 4: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M440/K148/440148745.PDF.

23 *See* Proposed Decision, at 35-36.

knowledge that Commissioners or ALJs may not have, meaning there is value in giving parties a voice to advocate for the submission of affordability metrics. If the Commission limits submission of metrics by default to GRCs, the Commission should adopt a process to allow parties to request affordability metrics from the Commissioner or ALJ. The Commissioner or ALJ should then be required to respond to that request with a determination of whether or not the affordability metrics will be submitted, and if not, explain why not. This provides a fair opportunity for parties interested in seeing the metrics and accountability for the Commission to continue to examine the impacts to customer affordability of cost recovery requests.

III. THE COMMISSION SHOULD ADOPT THE PROPOSED DECISION'S REQUIREMENTS FOR ADDITIONAL CONTEXTUAL DATA WITH THE AFFORDABILITY METRICS TO ENHANCE VISIBILITY INTO IOU COSTS

The Proposed Decision's requirements for IOUs to supply more context alongside affordability metrics will make them more useful for decision-makers and should be adopted. The Proposed Decision requires IOUs to provide additional pieces of context alongside submissions of the affordability metrics, including:

- Quantitative summary of change to affordability for the utility's most disadvantaged customers and narrative analysis reconciling the quantitative changes with affordability;
- Historical and projected residential average rate growth compared to inflation; and
- Current and projected GRC revenue growth compared to inflation.[24]

The context the additional data and graphs the Proposed Decision requires increase the usefulness of the affordability metrics by comparing cost recovery requests and impacts to inflation rates. This provides a meaningful anchor point for the Commission and the public to compare, enabling decision-makers to better understand the reasonableness of requests.

[24] *Id.* at 69, OP 1.

Requiring additional context also helps demonstrate that IOU cost recovery requests are not happening in a vacuum. They are part of a larger system, which requires making difficult decisions to balance priorities. To effectively balance priorities, the Commission should have a clearer picture of cost recovery impacts, which additional context will provide. Therefore, the Commission should adopt the Proposed Decision's requirements to supply more context alongside affordability metrics.

IV. THE PROPOSED DECISION SHOULD PROVIDE FURTHER DISCUSSION ON NEXT STEPS FOR COMMISSION CONSIDERATION TO CONTINUE ADDRESSING AFFORDABILITY

The Proposed Decision should include more detail on next steps for the Commission to continue to address affordability. The Proposed Decision states that the affordability metrics and information gained in this proceeding "will continue to inform the Commission's assessment of issues presented in proceedings."[25] While CalCCA supports this continued assessment by the Commission, the Proposed Decision lacks concrete next steps. Affordability will continue to be an issue, and the Commission has an opportunity to propose ways to follow up on its recommended strategies for reducing electricity bills. Specifically, the Proposed Decision mentions three strategies for reducing electricity bills that stem from the Commission's response to Governor Newsom's Executive Order N-5-24: (1) control growth in utility spending; (2) find additional funding sources for wildfire mitigation, rooftop solar cost-shift, and future cost-shifts, low-income assistance, non-cost-effective programs; and (3) reduce rate inequities that exempt advantaged customers from paying fixed costs.[26] For meaningful progress and for public assurance, the Proposed Decision should be amended with further discussion on current or future venues for discussing these strategies. For example, what actions will the Commission take to support finding

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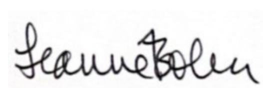
25 *Id.* at 63.
26 *Id.* at 62.

additional funding sources for cost drivers like wildfire mitigation? Where and how will the Commission address rate inequities that exempt advantaged customers from paying fixed costs? California's issues with ensuring affordable electricity are not over, so the Commission must be more specific about next steps to ensure affordability continues to be a priority to fulfill its obligations to customers.

V. 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, attached hereto.

Respectfully submitted,



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

December 3, 2025

APPENDIX A
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION UPDATING THE AFFORDABILITY FRAMEWORK AND CLOSING PROCEEDING

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

~~6. Reducing the number of individual proceedings in which affordability metrics are required, combined with requiring additional context to be included with the metrics will generate more robust information about affordability.~~

CONCLUSIONS OF LAW

~~3. The criteria for including affordability metrics in individual proceedings should be narrowed to apply only to General Rate Case applications where the revenue increase is estimated to exceed more than one percent of the currently authorized revenues.~~

ORDERING PARAGRAPHS

1. Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, Southern California Gas Company, PacifiCorp, Liberty Utilities (CalPeco Electric) LLC, Southwest Gas Corporation, and Bear Valley Electric Company, Inc. shall include in **~~all initial General Rate Case (GRC) Phase 1 applications~~** **<u>any application or proceeding</u>** where the revenue increase is estimated to exceed one percent of currently authorized revenues systemwide for a single fuel, the following in accordance with the specifications in Appendix A:

a. Updated affordability metrics associated with revenues in effect at the time of filing the GRC application;
b. Changes in the affordability metrics associated with the proposed revenue request;
c. Quantitative summary of change to affordability for the utility's most disadvantaged customers and narrative analysis reconciling the quantitative changes with affordability;
d. Historical and projected residential average rate growth compared to inflation; and
e. Current and projected GRC revenue growth compared to inflation.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and Perform Long-Term Gas System Planning.	Rulemaking 24-09-012 (Filed September 26, 2024)

OPENING COMMENTS OF MARIN CLEAN ENERGY ON THE PROPOSED DECISION DESIGNATING INITIAL PRIORITY NEIGHBORHOOD DECARBONIZATION ZONES

Wade Stano
Senior Policy Counsel
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6024
Email: wstano@mcecleanenergy.org

December 3, 2025

Table of Authorities

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and Perform Long-Term Gas System Planning.	Rulemaking 24-09-012 (Filed September 26, 2024)

OPENING COMMENTS OF MARIN CLEAN ENERGY ON THE PROPOSED DECISION DESIGNATING INITIAL PRIORITY NEIGHBORHOOD DECARBONIZATION ZONES

I. Introduction

Pursuant to 14.3 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission" or "CPUC"), Marin Clean Energy ("MCE"), respectfully submits these Opening Comments on the *Proposed Decision Designating Initial Priority Neighborhood Decarbonization Zones* ("Proposed Decision" or "PD") mailed on November 13th, 2025. MCE thanks the Commission for the opportunity to comment on the Commission's designation of initial priority neighborhood decarbonization zones in compliance with Senate Bill 1221 (Min, 2024). MCE is a local government entity and community choice aggregator ("CCA") committed to advancing beneficial building decarbonization solutions for its customers and statewide.[1] MCE offers its explicit support for the designation of 13 initial priority neighborhood decarbonization zones within its service area.[2] MCE is equipped to leverage its complementary programs in support

[1] MCE, How MCE Works, https://mcecleanenergy.org/how-mce-works/.
[2] MCE, Areas We Serve, https://mcecleanenergy.org/areas-we-serve/ (MCE provides clean electricity service and clean energy programs to 38 member communities across Contra Costa, Marin, Napa, and Solano counties). *See* **Attachment A** for listed decarbonization zones.

of successful pilot implementation when appropriate and applicable.[3] MCE recommends the Commission provide additional pathways for communities to site, design and implement Senate Bill 1221 Neighborhood Decarbonization Zone pilot projects.

II. Discussion

a. MCE is a Supportive Local Government of Preliminary Neighborhood Decarbonization Zones

MCE supports the Commission's designation of preliminary decarbonization zones at the census tract level.[4] MCE appreciates the Commission and commenting parties' recognition of the importance of local government partners in optimal pilot selection, design and implementation in compliance with Senate Bill 1221.[5] As stated in previous comments, MCE is prepared to leverage its complementary programs and their relevant resources to support successful implementation of pilot projects when suitable.[6] MCE supports the 13 proposed preliminary decarbonization zones within its service area.[7]

b. MCE Requests the Commission Provide More Pathways for Communities to Influence Neighborhood Decarbonization Zone Pilot Projects

MCE supports the Commission's requirement for additional community outreach on Senate Bill 1221 pilot projects.[8] MCE's experience as a program administrator of related building decarbonization and energy efficiency programs informs its belief that building decarbonization projects require significant community input on issues like site selection, program offerings,

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[3] MCE, Explore All Programs and Offers, https://mcecleanenergy.org/explore-programs-and-offers/.
[4] PD at pp. 26-27.
[5] PD at pp. 28-29; Senate Bill 1221 (Min, 2024), California Public Utilities Code Section 662 (a)(3).
[6] MCE Opening Comments on ALJ Ruling on Designating Priority Decarbonization Zones, pp. 2-3; Attachment A-2.
[7] *See* **Attachment A** for listed decarbonization zones.
[8] PD at p. 23.

technical support and evaluation.[9] There is not one building decarbonization pilot design that can meet the diverse energy, health and affordability needs of all Californians. Additionally, some technologies like electric heat pumps may be new to potential participants and require more education and support.[10] As the decarbonization zone maps with census tract data indicate, these projects are by design a hyperlocal endeavor. Successful implementation will require frequent, meaningful community input from each participating community both consistent with Senate Bill 1221's explicit requirements[11] and more broadly.

While MCE supports the additional outreach required by the gas corporations in the Decision,[12] MCE recommends the Commission amend the Decision to detail more requirements and opportunities for community engagement on both site selection and pilot project design. As community outreach is most effective when conducted by trusted messengers,[13] MCE recommends the Commission additionally require gas corporations to prioritize partnerships with trusted community-based organizations and local partners on community outreach. These

[9] MCE, RE: Marin Clean Energy on the Request for Information RE: Equitable Building Decarbonization Program (DOCKET NO. 22-DECARB-03), CEC, Docket No. 22-DECARB-03, 2023, pp. 3-4.
[10] DNV, MCE LOW-INCOME FAMILIES AND TENANTS PILOT PROGRAM EVALUATION, 2021, p. 34 ("Given the newness of the technology [electric heat pumps] and the lack of customer exposure to it, there could be potential misconceptions about and misuse of heat pump technology.").
[11] Senate Bill 1221 (Min, 2024) California Public Utilities Code Section 663(a) - (b)(requiring a 67% threshold of community support for each pilot project).
[12] PD at pp. 24-26.
[13] California Energy Commission, Low-Income Barriers Study, Part A: Overcoming Barriers to Energy Efficiency and Renewables for Low-Income Customers and Small Business Contracting Opportunities in Disadvantaged Communities, 2016, p. 9 ("The Legislature should direct funding for all state programs to collaborate with trusted and qualified community-based organizations in community-centric delivery of clean energy programs, in coordination with local government").

partners are well positioned to leverage existing relationships with community members and their expertise on culturally competent and in-language outreach.[14]

III. Conclusion

MCE thanks the Commission for the opportunity to provide comments on the preliminary decarbonization zones. MCE looks forward to partnering with the Commission, parties and community stakeholders to support beneficial community-led decarbonization pilots in its service area and statewide.

Dated: December 3, 2025.

Respectfully submitted,

/s/ Wade Stano
Wade Stano
Senior Policy Counsel
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6024
Email: wstano@mcecleanenergy.org

[14] *Id*. at pp. 48-49.

ATTACHMENT A

PRELIMINARY NEIGHBORHOOD DECARBONIZATION ZONES

MCE identified census tracts within its service area according to the city and counties identified in *Appendix A*. MCE recognizes census tracts include areas beyond those listed below. MCE highlights the proposed preliminary neighborhood decarbonization zones in cities and counties within its service area.

MCE supports the following preliminary neighborhood decarbonization zones listed in *Appendix A*:

Number	**Tract ID**	**City**	**County**
1.	**6001420200**	**El Cerrito**	**Contra Costa**
2.	**6013388000**	**El Cerrito**	**Contra Costa**
3.	**6013387000**	**El Cerrito**	**Contra Costa**
4.	**6013390200**	**El Cerrito**	**Contra Costa**
5.	**6013391000**	**El Cerrito**	**Contra Costa**
6.	**6013389100**	**El Cerrito**	**Contra Costa**
7.	**6013383000**	**El Cerrito, Richmond**	**Contra Costa**
8.	**6013384000**	**El Cerrito; Richmond**	**Contra Costa**
9.	**6013313105**	**Pittsburg**	**Contra Costa**
10.	**6013313206**	**Pittsburg**	**Contra Costa**
11.	**6013313107**	**Pittsburg**	**Contra Costa**
12.	**6013307205**	**Pittsburg**	**Contra Costa**
13.	**6013379000**	**Richmond**	**Contra Costa**

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

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2026 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U 39 E)	Application No. 25-05-011 (Filed May 15, 2025)
Expedited Application of Pacific Gas and Electric Company Pursuant to the Commissions Approved Energy Resource Recovery Account (ERRA) Trigger Mechanism (U 39 E)	Application No. 25-09-015 (Filed September 30, 2025)

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

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

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

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

Counsel to
CALIFORNIA COMMUNITY CHOICE ASSOCIATION

December 4, 2025

SUBJECT MATTER INDEX

TABLE OF AUTHORITIES

SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS[1]

- The Commission should reject PG&E's pre-2019 banked REC proposal. Allowing PG&E to use pre-2019 banked RECs for bundled customer RPS compliance without compensating the departed load customers who paid for a portion of those RECs is a clear violation of Section 366.2(g) of the California Public Utilities Code. PG&E's opening comments on the PD emphasize the alleged bundled customer "affordability" benefits of its proposal to value pre-2019 banked RECs at zero dollars, but willfully ignores that its proposal would achieve any "affordability" benefits for bundled customers only by violating indifference and shifting costs onto departed customers. PG&E's unlawful proposal exacerbates what will already be a massive PCIA rate hike for departed customers and the PD's conclusion adopting that proposal is reversible error.

- The Commission should apply SCE's interim SoD methodology to all technology types in PG&E's PCIA-eligible RA portfolio, including but not limited to battery energy storage. SCE's interim SoD methodology adapts PCIA ratemaking—specifically, RA valuation—to reflect the implementation of the SoD RA compliance framework. To the extent the Commission believes PG&E's current RA valuation methodology must change on an interim basis in light of SoD implementation, the Commission should apply SCE's interim method to PG&E's RA portfolio wholesale, and should not apply that method piecemeal to certain technologies but not others.

- The Commission should adopt the recommendations in CalCCA's Opening Comments on the Proposed Decision.

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
REPLY COMMENTS ON PROPOSED DECISION

California Community Choice Association[2] (CalCCA) submits these Reply Comments on Administrative Law Judge Fox's *[Proposed] Decision Approving Pacific Gas and Electric Company's 2026 Energy Resource Recovery Account Related Forecast Revenue Requirement and 2025 Electric Sales Forecast* (PD) pursuant to Rule 14.3 of the Rules of Practice and Procedure of the California Public Utilities Commission and the procedural schedule established in the Assigned Commissioner's Scoping Memo and Ruling (confirmed by the Administrative Law Judge's November 24, 2025, E-Mail Ruling Clarifying Comment Due Dates), which modifies the time periods for comments and reply comments prescribed by Rule 14.3.[3]

I. INTRODUCTION

Pacific Gas and Electric Company's (PG&E) Renewables Portfolio Standard (RPS) strategy drives its unlawful pre-2019 banked Renewable Energy Credits (REC) proposal. The utility plans to sell its Renewables Portfolio Standard (RPS) resources and leverage its extensive bank of pre-2019 REC to meet its bundled customer compliance obligations for the foreseeable future while it re-establishes its RPS portfolio, while valuing those RECs at zero dollars.[4] This approach, according to PG&E, is an "affordability measure" for bundled service customers.[5]

But PG&E's approach can only reduce the costs bundled service customers pay through rates by violating the indifference principle and unlawfully shifting those costs on to departed load. The Power Charge Indifference Adjustment (PCIA) is a zero-sum game: any affordability improvement for bundled customers comes with a corresponding affordability worsening for departed customers. PG&E's pre-2019 banked REC proposal is not a true ***affordability*** measure,

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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] Assigned Commissioner's Scoping Memo and Ruling at 5 (Jul. 31, 2025) (Scoping Memo).

[4] *See* Pacific Gas and Electric Company's (U 39 E) Comments on the Proposed Decision at 4 (Dec. 1, 2025) (PG&E PD Comments).

[5] *Id*.

which would reduce utility costs and corresponding rates for bundled and departed customers alike. Put differently, free benefits are obviously cheaper than the benefits you purchase, but that does not make the free benefit fair, reasonable, or lawful.

PG&E's disregard for the mechanics of the PCIA and its disinterest in the impacts of its proposal on departed load are alarming, but the Commission must not ignore those mechanics or that impact. A decision adopting PG&E's banked REC proposal, even on an "interim" basis, would violate Section 366.2(g) of the Public Utilities Code, which requires the valuation of pre-2019 banked RECs at the RPS Adder. Such legal error would further subject the Commission's decision to reversal on appeal.[6] Further, adopting PG&E's banked REC proposal would significantly exacerbate the PCIA rate increases that community choice aggregator (CCA) customers will already experience in 2026.

As CalCCA describes in detail in its PD opening comments, the PD approves enormous rate increases for CCA customers. Those rate increases are driven by the Commission's decision incorporating a new methodology for calculating the Resource Adequacy (RA) Market Price Benchmark (MPB) into rates, PG&E's unlawful banked REC proposal, and market forces that have driven down the value of PG&E's PCIA portfolio. 2026 PCIA rates will increase dramatically for departed customers across all vintages, but residential customers in the 2021-2024 vintages will be worst hit. Customers in the 2021 and 2022 vintages will experience increases of **near eight cents per kilowatt-hour**, and customers in the 2023 and 2024 vintages will experience increases of **over eight cents per kilowatt-hour**. PG&E turns a blind eye to these rate increases and omits any mention of the contribution its "affordability" measure (its proposal to value pre-2019 banked RECs at zero dollars) will make to this affordability crisis.

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[6] The Commission's decision is also subject to reversal on appeal as perpetuating prohibited retroactive ratemaking by applying a final RA MPB derived from the methodology established in Decision (D.) 25-06-049. *See* A.25-05-011, *California Community Choice Association's Opening Brief*, pp. 75-93 (Oct. 24, 2025). CalCCA has appealed D.25-06-049 to the California Court of Appeal, Third Division. *See California Community Choice Association v. California Public Utilities Commission,* Case No. C105174 (Cal. Court of Appeal, Third Appellate District) (Filed Dec. 1, 2025). CalCCA's Petition for Writ of Review argues that the Commission's decision on the new RA MPB methodology constitutes "general ratemaking" and violates section 728's prohibition against retroactive ratemaking. CalCCA continues to assert that the Commission's implementation of that new methodology in this Proposed Decision is unlawful. *See* CalCCA Opening Brief at 75-93. And while the procedural recommendations CalCCA made in its Opening Brief were rendered moot due to the dismissal of the CalCCA's Application for Rehearing of D.25-06-049, *see* CalCCA Reply Brief at 22, the underlying unlawfulness of the retroactive application of the new RA MPB methodology is not, and remains on appeal through the Petition for Writ of Review.

The Commission should therefore reject PG&E's pre-2019 banked REC valuation proposal. Consistent with Section 366.2(g), Commission precedent, and prior PG&E practice, the Commission should value pre-2019 banked RECs at the applicable RPS Adder in the year in which PG&E uses the RECs for RPS compliance, and credit customers based on their PCIA vintage, either permanently or on an interim basis pending consideration of the issue in Phase 2 of the PCIA rulemaking (Rulemaking 25-02-005).

CalCCA's comments on the PD explain in detail the revisions to the PD that are required with respect to its discussion of PG&E's pre-2019 banked REC valuation proposal. These reply comments focus on PG&E's latest proposal for calculating the RA value of its PCIA-eligible portfolio. In this proceeding, PG&E has already advanced two new proposals to modify its methodology for calculating the RA value of its PCIA portfolio. The PD correctly rejects both of those proposals, finding neither proposal would result in a reasonable outcome.[7] In its comments on the PD, PG&E does not challenge that conclusion, but instead proposes a *third* valuation methodology. PG&E asks the Commission to retain its existing methodology for calculating the RA value of its non-energy storage PCIA resources, and apply Southern California Edison Company's (SCE) interim Slice-of-Day (SoD) methodology to *only* the energy storage resources in its portfolio.

The Commission should reject that proposal and apply SCE's interim SoD methodology to PG&E's entire PCIA portfolio, including all technology types in that portfolio. As a threshold matter, PG&E's now *third* proposal on this issue in this case is procedurally defective, as it is raised after the record has closed and leaves parties no opportunity to evaluate the impact of that proposal on the RA value of PG&E's PCIA portfolio or on PCIA rates. But PG&E also ignores the basic premise of the PD's decision to adopt changes to PG&E's RA valuation practices in this proceeding. The PD adopts those changes to reflect the Commission's implementation of the SoD framework for RA program compliance. That framework applies to *all resources*, not just energy storage resources. Therefore, any change to PCIA ratemaking on account of SoD implementation should apply to all technology types. The record of this proceeding demonstrates SCE's method is appropriately differentiated by technology type and can therefore be applied to PG&E's entire PCIA portfolio. Indeed, the Commission has already approved SCE's use of its methodology to

[7] PD at 34.

value all technology types in SCE's portfolio so there is no reason why the Commission should break from that precedent in PG&E's context.

II. THE COMMISSION SHOULD NOT LIMIT THE APPLICATION OF SCE'S SLICE OF DAY METHODOLOGY TO PG&E'S STORAGE RESOURCES

PG&E asks the Commission to revise the Proposed Decision and apply SCE's SoD methodology only to energy storage resources, and not to any other technology type in PG&E's resource portfolio.[8] In essence, PG&E now seeks to keep its current approach to RA valuation intact for all technology types save energy storage resources, but modify its approach for that single technology type. This is PG&E's *third* RA valuation proposal in this proceeding. The Commission should reject it, just as it rejected PG&E's first two RA valuation proposals. As a threshold matter, PG&E's proposal is procedurally defective. The record has closed and parties have no opportunity to evaluate how the new proposal would impact the RA value of PG&E's PCIA portfolio and PCIA rates. But PG&E's proposal is also substantively flawed, because it ignores the PD's premise for adopting changes to PG&E's existing RA valuation practices.

The PD adopts changes to those practices because "the Commission's RA regulatory program has changed enough to warrant a response in this expedited proceeding."[9] That change to the RA program is the Commission's implementation of the SoD framework. Indeed, PG&E insisted, and continues to insist, that SoD implementation requires changes to the manner in which RA quantity is calculated for PCIA ratemaking purposes. In its opening brief, for instance, PG&E states, referring to SoD implementation: "There is no question that significant regulatory changes concerning RA compliance have been adopted by the Commission, and as such, adjustments need to be incorporated into PG&E's Retained RA calculation."[10] Nowhere in its testimony or briefs does PG&E claim SoD implementation requires changes *only* to its valuation of RA from energy storage resources.

The SoD framework does not apply only to energy storage resources—it applies to *all technology types*. Therefore, any change to PCIA ratemaking on account of SoD implementation should apply to all technology types. As CalCCA pointed out on several occasions in this proceeding, the impacts of SoD implementation on the PCIA—including all technology types in

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8 PG&E PD Comments at 3.

9 PD at 34.

10 PG&E Opening Brief at 38-39.

PG&E's PCIA-eligible portfolios—merit careful examination in a rulemaking, where the Commission can consider whether changes are necessary to either RA *price* or RA *quantity* (or both).[11] However, to the extent the Commission is inclined to adopt an interim modification to PG&E's existing RA valuation methodology until it more comprehensively revisits that methodology in a rulemaking, PG&E offers no principled basis for the Commission to apply that interim modification *only* to energy storage resources.

PG&E claims "[t]here is no record upon which PG&E can make adjustments for SOD for resources other than energy storage resources," but that claim rings hollow. CalCCA's direct testimony discusses SCE's interim SoD method broadly, including its application to non-energy storage resources such as baseload and intermittent resources. CalCCA witness Dickman explains: "[a]ccording to the SCE Interim SOD Method, baseload resources that deliver consistent output throughout the day continue to count up to their NQC for the month. For intermittent resources (e.g., wind, solar), the RA quantity is the average of their hourly exceedance values, which vary depending on the region and technology."[12] SCE's method is therefore appropriately differentiated by technology type and can be applied to PG&E's entire PCIA portfolio based on the record of this proceeding. Importantly, in SCE's 2025 ERRA Forecast proceeding, the Commission approved SCE's use of its methodology to value all technology types in SCE's portfolio,[13] so there should be no doubt that methodology can be applied to all technology types. PG&E offers no reason for the Commission to break from that precedent in this case.

III. CONCLUSION

For the reasons stated herein, and in CalCCA's Opening Comments, the Commission should adopt the recommendations in CalCCA's Opening Comments, reject PG&E's recommendation that SCE's SoD methodology apply only to energy storage resources, and grant any other relief the Commission deems just and reasonable.

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[11] *See, e.g.* CalCCA Opening Brief at 68-71.

[12] Exh. CalCCA-01C at 30.

[13] Application of Southern California Edison Company (U 338 E) for Approval of Its 2025 ERRA Forecast Proceeding Revenue Requirement, A.24-05-007, D.24-12-039 at 75 (Dec. 23, 2024).

Respectfully submitted,

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

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Counsel to CALIFORNIA COMMUNITY CHOICE ASSOCIATION

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Consider New Approaches to Disconnections and Reconnections to Improve Energy Access and Contain Costs.	R.18-07-005

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON E-MAIL RULING ON ARREARAGE-RELATED ASSISTANCE PROGRAMS

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

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

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TABLE OF CONTENTS

SUMMARY OF RECOMMENDATIONS[1]

As set forth below, CalCCA recommends the Commission take the following actions:

- Reject PG&E's, SCE's, the Joint Utilities', and Cal Advocates' recommendation to discontinue PIPP after the pilot concludes, to provide needed support to customers;
- Reject PG&E and SCE's recommendation to discontinue AMP because the Commission can address program costs through adjusting participation caps if necessary;
- Reject the recommendation from PG&E that the Commission should remove the current disconnection rate caps because Californians still need disconnection protections; and
- Conduct another evaluation of AMP in five years to ensure the program continues to serve customers and meet program goals.

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

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Consider New Approaches to Disconnections and Reconnections to Improve Energy Access and Contain Costs.	R.18-07-005

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON E-MAIL RULING ON ARREARAGE-RELATED ASSISTANCE PROGRAMS

California Community Choice Association[2] (CalCCA) submits these reply comments pursuant to the *E-Mail Ruling on Arrearage Related Assistance Programs*[3] (Ruling), dated October 13, 2025, and the *Email Ruling Modifying CBO-Related Questions and Extending Comment Deadline*, dated October 21, 2025.[4] The Ruling provides parties the opportunity to comment on a procedural path forward for three of the Commission's programs that were developed to assist customers in avoiding or paying down their past-due balances: the Arrearage Management Payment Plan Program (AMP), the Community Based Organization Arrears Case Management Pilot Program, and the Percentage of Income Payment Plan Pilot Program (PIPP).[5]

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

3 *E-Mail Ruling on Arrearage Related Assistance Programs*, Rulemaking (R.) 18-07-005 (Oct. 13, 2025): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M583/K960/583960513.PDF.

4 *Email Ruling Modifying CBO-Related Questions and Extending Comment Deadline*, R.18-07-005 (Oct. 21, 2025) (CBO Ruling): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M584/K626/584626082.PDF.

5 All references herein to party Opening Comments are to the Opening Comments filed in this Rulemaking 18-07-005 on or about November 14, 2025.

I. INTRODUCTION

Despite the affordability crisis faced by Californians with their utility bills, Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E)/Southern California Gas Company (SoCalGas) (the Joint Utilities), and The Public Advocates Office at the California Public Utilities Commission (Cal Advocates) all recommend discontinuing either all or some of the ratepayer protections established by the Commission through AMP, PIPP, and the disconnection rate caps. Instead, as set forth below, the Commission should continue all of these protections, with an eye towards their improvement as recommended by the Center for Accessible Technology, National Consumer Law Center, and The Utility Reform Network (collectively, the Joint Consumers) and related to further evaluation of AMP.

First, the Commission should reject the recommendations of PG&E, SCE, the Joint Utilities, and Cal Advocates to discontinue PIPP after its original sunset date of October 1, 2026.[6] In the current electric bill affordability crisis affecting Californians, PIPP has helped thousands of low-income customers by capping bills and allowing customers to keep their homes safer and more comfortable. While PG&E and Cal Advocates cite to the PIPP evaluation findings on not increasing on-time bill payments[7] or meeting the pilot's goal of encouraging participation in other energy-saving programs[8] as a reason for discontinuation, in actuality these are areas of opportunities to course-correct in moving from a pilot to a permanent program to better serve

6 PG&E Opening Comments, at 6; SCE Opening Comments, at 4; Joint Utilities Opening Comments, at 2; Cal Advocates Opening Comments, at 3.

7 *See* Cal Advocates Opening Comments, at 4 (citing PIPP's increased affordability for participants did not result in increased on-time bill payments for energy services).

8 *See* PG&E Opening Comments, at 6 (citing the PIPP Evaluation's finding that PIPP did not meet its goal of encouraging participation in other energy management programs.)

customers. SCE and the Joint Utilities argue that PIPP's costs outweigh its benefits,[9] but this is not a finding of the PIPP evaluation, nor do the parties have quantitative evidence to back up the claim. Discontinuing PIPP is directly counter to the evaluator's recommendation and would unjustifiably strip these affordability benefits from customers and expose low-income customers to increased economic hardship, despite the fact that customer bills remain at all-time high.

Second, PG&E and SCE recommend discontinuing AMP after its initial sunset date.[10] Similar to PIPP, AMP has help thousands of customers to keep their lights on. AMP's arrearage forgiveness promotes on-time bill payments by forgiving portions of customer arrearages for each on-time bill payment. SCE loosely suggests that AMP may be at a natural conclusion, while PG&E takes a stronger stance and argues AMP's high costs warrant discontinuing it. However, the AMP Evaluation estimates that AMP's implementation is relatively efficient, with approximately 95 percent of its costs coming from the arrearage forgiveness itself. This indicates that the Commission can control costs through adjusting participation caps of the program if it deems costs too high. Again, discontinuing this program would remove a valuable affordability option for thousands of Californians to tackle the high and rising costs of electric service.

Third, PG&E argues for the removal of disconnection rate caps as recommended by the AMP Evaluation.[11] Doing so would cause unnecessary harm to many customers and conflict with the goals the Commission and the legislature have introduced to protect customers from disconnections. Customer bills have continued to increase since California passed Senate Bill (SB) 598, which directed the Commission to pursue policies, rules, and regulations designed to

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[9] SCE Opening Comments, at 3; Joint Utilities Opening Comments, at 2.

[10] *See* PG&E Opening Comments, at 6 (responding to whether AMP should continue until its scheduled sunset date); *see also* SCE Opening Comments, at 5 (suggesting AMP is at a natural point of conclusion).

[11] PG&E Opening Comments, at 6.

reduce disconnections.[12] Additionally, the conclusion from the AMP Evaluation on which the recommendation to remove disconnection rate caps is based lacks quantitative backing and stems from a survey given to IOU staff about their perceived concerns.[13] Difficulties with the affordability of electric bills still exist, and the Commission will only risk increasing disconnections if the current disconnection rate caps are removed.

Fourth, the Joint Consumers recommend adding an AMP evaluation in five years after it has begun a more permanent implementation.[14] This is a common-sense recommendation because program evaluations are a best practice for adjusting programs to improve performance over time.

As set forth below, CalCCA recommends the Commission take the following actions:

- Reject PG&E's, SCE's, the Joint Utilities', and Cal Advocates' recommendation to discontinue PIPP after the pilot concludes, given customers continue to need this support;
- Reject PG&E's and SCE's recommendation to discontinue AMP because the Commission can address program costs through adjusting participation caps if necessary;
- Reject the recommendation from PG&E that the Commission remove the current disconnection rate caps because Californians still need disconnection protections; and
- Adopt the Joint Consumers' recommendation to conduct another AMP evaluation in five years to ensure the program continues to serve customers and meet program goals.

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[12] Senate Bill 598 (Hueso, Chapter 362, Statutes of 2017): https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB598.

[13] *See* AMP Evaluation, at 10-11 (listing challenges and concerns expressed from IOU managers and staff, including payment incentives).

[14] *See* Joint Consumers Opening Comments, at 12 (recommending that the Commission consider conducting another evaluation of AMP in five years).

II. PG&E'S, SCE'S, THE JOINT UTILITIES', AND CAL ADVOCATES' RECOMMENDATION TO DISCONTINUE PIPP AFTER THE PILOT CONCLUDES SHOULD BE REJECTED

The Commission should reject recommendations of PG&E, SCE, the Joint Utilities, and Cal Advocates to discontinue PIPP after the pilot concludes.[15] *First*, PG&E and Cal Advocates criticize portions of the PIPP evaluation, including the pilot not resulting in on-time bill payments[16] and not meeting the pilot's goal of encouraging participation in other energy-saving programs.[17] The issues PG&E and Cal Advocates cite are important metrics that can be addressed through program modifications after the pilot has concluded. Rather than viewing them as reasons to discontinue, the Commission should view the recommendations related to on-time bill payments and participation in other programs as opportunities to learn and improve the program on a long-term basis for customers. PIPP was established as a pilot precisely so the Commission could learn what works, what does not, and what modifications are necessary prior to full implementation.

Second, both SCE and the Joint Utilities believe that PIPP's costs outweigh its benefits. SCE asserts that PIPP "is not a scalable solution,"[18] because funding for PIPP contributes to upward pressure on rates in general. The Joint Utilities claim that "overall program costs significantly outweighed the benefits."[19] These arguments ignore the PIPP Evaluation's overall support for the continuation of PIPP and do not warrant stripping customers of the benefits a long-term implementation of PIPP can provide. The Commission set a four-year, preliminary

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15 PG&E Opening Comments, at 6; SCE Opening Comments, at 4; Joint Utilities Opening Comments, at 2; Cal Advocates Opening Comments, at 3.

16 *See* Cal Advocates Opening Comments, at 4 (citing PIPP's increased affordability for participants did not result in increased on-time bill payments for energy services).

17 *See* PG&E Opening Comments, at 6 (citing the PIPP Evaluation's finding that PIPP did not meet its goal of encouraging participation in other energy management programs.)

18 SCE Opening Comments, at 3.

19 Joint Utilities Opening Comments, at 2.

budget maximum for SCE and SoCalGas's PIPP implementation in Decision (D.) 21-10-012 at $18,798,250 for covering the cost of bill subsidies and administration for up to 9,000 participants.[20] Assuming SCE's budget from this total is proportional to its participant cap of 4,000, SCE's maximum budget is approximately $8,354,778 for a four-year implementation of the pilot. Decision 25-09-030 approves SCE's most recent general rate case revenue requirement of $9.664 billion for SCE's test year alone. SCE's budget for PIPP implementation pales in comparison, indicating that the impacts to non-participating customers in terms of rates are minuscule, but provide significant bill relief to those most in need.

To support this claim, the Joint Utilities assert a conclusion that the PIPP Evaluation never makes:

> The evaluation report notes that while participants experienced slight reductions in arrears, the overall program costs significantly outweighed the benefits.[21]

The Joint Utilities cite the excerpt from the PIPP Evaluation that details "PIPP had a positive impact on the amount of the bill paid but not on the number of payments made or the percent of participants who made 12 or more payments."[22] This statement does not equate to PIPP's costs significantly outweighing its benefits. In fact, the PIPP Evaluation's recommendation to continue a permanent version of PIPP indicates the opposite conclusion.[23] For these reasons, the arguments against the PIPP Evaluation from PG&E, Cal Advocates, SCE, and the Joint Utilities

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[20] D.21-10-012, *Decision Authorizing Percentage of Income Payment Plan Pilot Programs*, R.18-07-005 (October 7, 2021), at 62, Table 3; SCE's participant cap is 4,000 and SoCalGas's participant cap is 5,000.

[21] Joint Utilities Opening Comments, at 2-3.

[22] PIPP Evaluation, at 76.

[23] *Id.*, at 78 (recommending the benefits offered by PIPP should be continued in the long-term, along with modifications to allow PIPP to achieve its goals).

do not justify discontinuing PIPP and leaving thousands of customers without needed assistance and should be rejected.

III. PG&E'S AND SCE'S RECOMMENDATION TO DISCONTINUE AMP SHOULD BE REJECTED BECAUSE THE COMMISSION CAN ADDRESS PROGRAM COSTS THROUGH ADJUSTING PARTICIPATION CAPS

PG&E's and SCE's recommendations to discontinue AMP should be rejected because doing so would remove a needed form of assistance for the most vulnerable customers. PG&E recommends that AMP be implemented through its original sunset date but discontinued thereafter.[24] SCE suggests that "it is possible that the program has fulfilled its intended purpose and may be approaching a natural conclusion."[25] Though SCE does not take a strong stance, PG&E argues:

> Although AMP undoubtedly aids individual customers who receive arrearage forgiveness while they remain enrolled in the program, the lack of sustained benefits (even when analyzing the most successful customers) relative to the program's ***high costs*** do not warrant extension beyond the October 1, 2026 sunset date.[26]

PG&E fails to differentiate costs in the AMP Evaluation between program administration and implementation costs, and the costs associated with forgiving arrearages for enrolled customers. Of the $657,272,801 in costs estimated by the AMP evaluation for electric utilities, approximately 95 percent was for arrearage forgiveness, meaning approximately five percent was for design and implementation of the program.[27] This indicates that the cost of running the program is approximately $35 million over four years, across three electric investor-owned utilities (IOU). Since the $35 million includes program design and evaluation, the actual

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24 PG&E Opening Comments, at 6 (responding to whether AMP should continue until its scheduled sunset date).

25 SCE Opening Comments, at 5.

26 PG&E Opening Comments, at 7 (emphasis added).

27 AMP Evaluation, at 95, Table IV-47.

administrative costs to run AMP across the three IOUs are even less.[28] Less than five percent of the program budget for administrative, marketing, and evaluation costs is lean compared to other Commission customer programs. For example, D.09-09-047 establishes a ten percent cost cap for IOU administrative costs alone for implementing energy efficiency programs, stating that ten percent is "consistent with national averages for other efficiency programs and our other clean energy programs."[29] This is separate from marketing and evaluation.

Overall, the Commission can adjust participant caps to adjust the overall budget for AMP in a meaningful way, since the vast majority of funds are used for arrearage forgiveness. This, paired with recommendations from the AMP evaluation to help customer program completion rates, will make implementing AMP even more efficient. Therefore, the Commission should reject arguments that AMP's costs are high enough to warrant discontinuing after its original sunset date, to continue to support customers with high arrearages, and to bring down the overall arrearages in California.

IV. THE RECOMMENDATION FROM PG&E TO REMOVE DISCONNECTION RATE CAPS SHOULD BE REJECTED BECAUSE CALIFORNIANS STILL NEED DISCONNECTION PROTECTIONS

The Commission should reject the recommendation from PG&E to remove disconnection rate caps because it would cause unnecessary harm to customers struggling to pay utility bills. The current disconnection rate caps were adopted by D.20-06-003,[30] induced by SB 598, and the need to mitigate public health impacts, tremendous hardship, undue stress, and overreliance on

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28 *Ibid*.

29 D.09-09-047, *Decision Approving 2010-2012 Energy Efficiency Portfolios and Budgets*, Application (A.) 08-07-021, A.08-07-022, A.08-07-023, A.08-07-031 (Sept. 24, 2009), at 5-6.

30 D.20-06-003, *Phase I Decision Adopting Rules and Policy Changes to Reduce Residential Customer Disconnections for the Larger California-Jurisdictional Energy Utilities*, R.18-07-005 (June 11, 2020), at 144, Ordering Paragraph 1.

emergency services caused by disconnections.[31] The risks and harm caused by disconnections still exist in 2025, and electric rates have only risen since SB 598 was signed, meaning customers still struggle to pay bills on time and in full. Despite this reality, PG&E argues for the removal of disconnection rate caps because "they disincentivize timely bill payment and increase costs to other ratepayers."[32]

This perspective is flawed for two reasons. *First*, PG&E references a conclusion from the AMP Evaluation that lacks quantitative backing. The concerns regarding disincentives for bill payment in the AMP Evaluation come from the IOU staff survey, not from any statistical analysis performed.[33] IOU staff perceptions and concerns are not enough to warrant removing important disconnection protections for customers. *Second*, the AMP framework itself incentivizes on-time payments by tying successful payments to arrearage forgiveness, helping customers move further away from the risk of disconnection. Removing this framework *and* removing disconnection rate caps would put customers back in the same position as before D.20-06-003 and SB 598 intervened: at risk and subject to unnecessary hardship. Therefore, the Commission should reject the recommendation from PG&E to remove disconnection rate caps.

V. THE JOINT CONSUMERS' RECOMMENDATION TO CONDUCT ANOTHER AMP EVALUATION IN FIVE YEARS TO ENSURE THE PROGRAM CONTINUES TO MEET CUSTOMER NEEDS SHOULD BE ADOPTED

The Joint Consumers' recommendation to conduct another AMP evaluation in five years is reasonable and should be adopted. Given that the program recommendations from the AMP evaluation may change how AMP is implemented, the Joint Consumers recommend performing

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31 *Id.,* at 140, Finding of Fact 2.

32 PG&E Opening Comments, at 6.

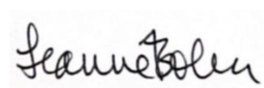
33 *See* AMP Evaluation, at 10-11 (listing challenges and concerns expressed from IOU managers and staff, including payment incentives).

another evaluation in five years.[34] Even if there are no program changes adopted and AMP is simply continued as-is, the Commission should conduct another evaluation. Fundamentally, program evaluation is a standard best practice for ensuring programs can be course-corrected. Holding regular studies of program performance ensures that practices can be adjusted to fit the changing needs of customers or new policies. The Commission should adopt this common-sense recommendation.

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

December 5, 2025

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34 *See* Joint Consumers Opening Comments, at 12 (recommending that the Commission consider conducting another evaluation of AMP in five years).

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Establish a Framework and Processes for Assessing the Affordability of Utility Service.	R.18-07-006

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON THE PROPOSED DECISION UPDATING THE AFFORDABILITY FRAMEWORK AND CLOSING PROCEEDING

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

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

December 8, 2025

TABLE OF CONTENTS

SUMMARY OF RECOMMENDATIONS[1]

As set forth below, CalCCA recommends the Commission action:

- Reject the Joint Utilities' and SCE's proposals to weaken the Proposed Decision by eliminating requirements for additional contextual information when submitting the affordability metrics.

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

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Establish a Framework and Processes for Assessing the Affordability of Utility Service.	R.18-07-006

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON THE PROPOSED DECISION UPDATING THE AFFORDABILITY FRAMEWORK AND CLOSING PROCEEDING

The California Community Choice Association[2] (CalCCA) submits these reply comments pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure[3] on the proposed *Decision Updating the Affordability Framework and Closing Proceeding* [4] (Proposed Decision), dated November 13, 2025.

I. INTRODUCTION

Affordability remains a major concern for Californians while electric rates continue to rise, as noted in Governor Newsom's October 2024 Executive Order requiring the Commission to examine methods to address these issues.[5] As the Proposed Decision closes this Affordability proceeding, it is imperative that the Commission's final requirements in this proceeding serve to optimize, rather than reduce, the Commission's affordability directives. Unfortunately, IOU Opening Comments demonstrate their requests to reduce Commission requirements associated

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

[4] Proposed *Decision Updating the Affordability Framework and Closing Proceeding*, Rulemaking (R) 18-07-006 (Nov. 13, 2025): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M586/K598/586598168.PDF.

[5] California Executive Order N-5-24 (Oct. 30, 2024): https://www.gov.ca.gov/wp-content/uploads/2024/10/energy-EO-10-30-24.pdf.

with demonstrating rate impacts and increases, which directly reduce the benefits of the affordability framework the Commission is establishing through this proceeding. For example, San Diego Gas & Electric Company and Southern California Gas Company (the Joint Utilities), and Southern California Edison Company (SCE), in their Opening Comments, oppose the Proposed Decision's directive to require additional contextual information when utilities submit the affordability metrics in their ratesetting proceedings to demonstrate rate impacts. Despite the arguments from the Joint Utilities and SCE, the additional context the Proposed Decision requires improves the usefulness and transparency of the affordability metrics to the Commission and the public, and should be adopted.[6]

Therefore, CalCCA recommends the Commission take the following action:

- Reject the Joint Utilities' and SCE's proposals to weaken the Proposed Decision by eliminating requirements for additional contextual information when submitting the affordability metrics.

II. THE JOINT UTILITIES' AND SCE'S RECOMMENDATIONS TO ELIMINATE THE REQUIREMENT FOR ADDITIONAL GRAPHICAL INFORMATION WHEN AFFORDABILITY METRICS ARE SUBMITTED IMPEDES TRANSPARANCY AND USEFULNESS OF THE METRICS AND SHOULD BE REJECTED

The Commission should reject recommendations from the Joint Utilities and SCE to eliminate the Proposed Decision's requirements for additional contextual information alongside the affordability metrics because doing so would impede the transparency and usefulness of the affordability metrics. SCE recommends removing three of the four graphs that the Proposed Decision requires IOUs provide for added contextual information when submitting the affordability metrics, and the Joint Utilities recommend removing all of them.[7] Rather than providing meaningful alternatives to address the Commission's clear interest in making the affordability metrics more robust and easier to interpret, the Joint Utilities and SCE request removal of these requirements. For the reasons set forth below, the Commission should reject recommendations to remove requirements for additional contextual information alongside the affordability metrics from the Proposed Decision.

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[6] All references herein to party Opening Comments are to the Opening Comments filed in this Rulemaking 18-07-006, on or about December 3, 2025.

[7] *See* SCE Opening Comments, at 7 (recommending the removal of tables 2-4 from the Proposed Decision's requirements for additional context); *see also* Joint Utilities Opening Comments, at iii.

A. The Joint Utilities Provide Insufficient Evidence to Warrant Removal of Requiring Additional Contextual Information with Affordability Metrics from the Proposed Decision

The Joint Utilities do not provide sufficient evidence to warrant removing the Proposed Decision's requirements for additional contextual data when IOUs submit the affordability metrics. The Joint Utilities assert that requiring the newly proposed contextual information is "unsupported by the record and the facts in this proceeding and constitutes legal and factual error."[8] Rather than provide reasons as to why the Commission should not adopt the affordability metric contextual data requirements from a qualitative perspective, the Joint Utilities only provide procedural counterarguments. These include: (1) insufficient record evidence to support Finding of Fact (FoF) 3, requiring a comparison of historical revenue and rate trends to inflation;[9] (2) failure to provide a factual basis for the inclusion of Consumer Price Index[10] (CPI) based graphs for context;[11] and (3) violation of the Joint Utilities' right to meaningfully participate in the proceeding.[12]

These arguments fall flat for several reasons and do not outweigh the usefulness and transparency the additional context provides. *First,* despite arguing these points for approximately four pages, the Joint Utilities do not comment on the usefulness of the additional contextual data or any reasons why their inclusion is detrimental to customers or the public. Nor do the Joint Utilities argue that the cost burden of such a requirement is unreasonable or suggest that further analysis is needed to understand the costs or feasibility.

Second, the Commission does not need to provide additional factual basis for use of CPI-based inflation rates than is already understood by the Commission and stakeholders in general. That is, the CPI is a nationally known, publicly available index tracked by the United States Bureau of Labor Statistics, and is often used for comparisons to inflation across industries. It is *common sense* that this public index provides a reasonable reference point for comparison and, therefore, adds context for affordability metrics.

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8 Joint Utilities Opening Comments, at iii.

9 *Id.*, at 4; *see also* Proposed Decision, at 65, FoF 3 ("Comparing historical revenue and rate trends to inflation and presenting these graphical trends as specified in this decision will provide context when affordability metrics are required to be filed in energy utility GRC applications.").

10 Consumer Price Index, Bureau of Labor Statistics (accessed Dec. 4, 2025): https://www.bls.gov/cpi/.

11 Joint Utilities Opening Comments, at 5-6.

12 *Id.,* at 7.

Third, the Joint Utilities argue that since this is the first time parties are seeing the proposal to include CPI-based comparisons, they do not have "meaningful opportunity to consider the analysis or to seek discovery or further guidance on the graphs or how they should be implemented."[13] It is unclear what further analysis the Joint Utilities need to agree that providing additional context alongside the affordability metrics offers relevant information for decision-makers. The lack of detail in demonstrating how the Joint Utilities' right to meaningful participation was violated by the Proposed Decision makes it difficult to understand what further analysis is desired or how more time could change the Proposed Decision's conclusion. For these reasons, the Joint Utilities' recommendations to remove the Proposed Decision's requirement for additional contextual information alongside affordability metrics should be rejected.

B. SCE's Proposal to Remove the Comparison Between Proposed Revenue Requirements and Inflation Ignores the Overall Usefulness of the Comparison and Should Be Rejected

The Commission should reject SCE's proposal to remove revenue requirement comparisons illustrated in Table 2 through Table 4 of the Proposed Decision because removal would stunt the added usefulness of the comparison itself. SCE recommends in its Opening Comments to remove from the Proposed Decision requirements for IOUs to include tables that present: (1) current and projected GRC revenue compared to historical and projected inflation; (2) current and projected revenue associated with operational expense approvals compared to historical and projected inflation; and (3) current and projected revenue associated with capital expense approvals compared to historical and projected inflation.[14] SCE asserts that inclusion of this information will "lead to misleading results,"[15] which could "lead some intervenors to propose…significant cuts to GRC Test Year or Post-Test Year capital expenditures."[16]

In addition to impeding the transparency and usefulness of the affordability metrics, SCE's recommendation for removal should be rejected for two reasons. *First*, SCE's opposition to the required contextual data underestimates the ability of the Commission and intervenors to carefully review the contents of GRC applications. SCE states that misinterpretation of the data:

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13 *Ibid*.

14 *See* SCE Opening Comments, at 7 (recommending the removal of tables 2-4 from the Proposed Decision's requirements for additional context); *see also* Proposed Decision, at 29-31, Tables 2 through 4.

15 Ibid.

16 *Id.*, at 8.

> [w]ould be unwarranted and detrimental to customers, as it would not only have little impact on the projected capital-related revenue growth shown in these tables but also impede the utility's ability to deploy the capital needed in the current GRC cycle to operate, maintain, and expand the electric grid to safely and reliably serve customers.[17]

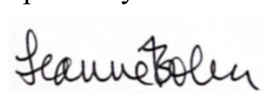
This statement assumes that the Commission would base decisions only on that contextual data, and that those decisions would be harmful to customers and the grid. This assumption also puts the cart before the horse by assuming what intervenors will argue in response to future GRC applications.

Second, in GRC applications, the burden to provide sufficient rationale to adopt a proposed revenue requirement is on SCE, not on the Commission or any other party. It is SCE's responsibility to ensure its application clearly and comprehensively explains why costs are reasonable and necessary. If there are capital costs included that are already approved as SCE mentions, then SCE should make that fact known in its application. The added contextual data the Proposed Decision requires allows the Commission and parties to have a better view of the many variables at play when making decisions. For these reasons, the Commission should reject SCE's proposal to remove from the Proposed Decision the requirements presented in Tables 2 through 4.

III. CONCLUSION

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

Respectfully submitted,



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

December 8, 2025

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17 SCE Opening Comments, at 8.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Improve the California Climate Credit.	R.25-07-013

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
POST-PREHEARING CONFERENCE STATEMENT

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

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

December 8, 2025

TABLE OF CONTENTS

SUMMARY OF RECOMMENDATIONS[1]

CalCCA makes the following recommendations:

- Reject the recommendation for a Phase 1A to immediately consider only modifying the timing of Climate Credit distribution, and instead in Phase 1 consider all issues concerning Climate Credit distribution timing simultaneously to ensure all Californians are considered;
- Utilize standard proceeding processes to develop the record; and
- Develop a data tool to allow parties to assess bill impacts of proposals.

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

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

Order Instituting Rulemaking to Improve the California Climate Credit.	R.25-07-013

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
POST-PREHEARING CONFERENCE STATEMENT**

The California Community Choice Association[2] (CalCCA) submits this Post-Prehearing Conference Statement (Post-PHC Statement) pursuant to Rule 7.2(a) of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure,[3] and *Email Ruling Allowing Post-PHC Statements and Responding to Inquiry Regarding the Deadline for Notices of Intent*[4] (Ruling), dated November 21, 2025.

I. INTRODUCTION

CalCCA appreciates Administrative Law Judge (ALJ) Maria Sotero's careful consideration of scope, schedule, and categorization of this proceeding through the agenda provided prior to the Prehearing Conference (PHC) and through discussion at the PHC. Also appreciated is the opportunity for parties to comment further through Post-PHC Statements. The

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

4 *Email Ruling Allowing Post-PHC Statements and Responding to Inquiry Regarding the Deadline for Notices of Intent*, Rulemaking (R.) 25-07-013 (Nov. 21, 2025).

Climate Credit is an important affordability measure for Californians. Careful consideration of potential impacts from any changes related to timing of the distribution and eligibility for the Climate Credit, as well as other potential changes, is crucial to ensuring the Climate Credit continues to benefit Californians as intended by the Legislature.

CalCCA's OIR Opening[5] and Reply Comments,[6] as well as remarks at the PHC reflected in the PHC Transcript,[7] include a full discussion of CalCCA's recommendations on scope. Overall, CalCCA supports the four OIR preliminary scoping items, including:

(1) Whether the Climate Credit eligibility criteria should be modified;

(2) Whether California Industry Assistance (CIA) implementation for emission-intensive trade-exposed (EITE) customers should be modified;

(3) How and when the Climate Credit should be distributed; and

(4) How should changes to the Climate Credit be communicated to customers?

In addition, CalCCA supports the additional scoping items proposed by the ALJ in the Agenda for the PHC, including:

(1) Whether the Commission should make changes to the Climate Credit calculation methodology;

(2) Considerations related to implementation of the provisions in Assembly Bill (AB) 1207;[8]

(3) Considerations regarding implementation of changes to relevant California Air Resources Board (CARB) regulations;

(4) Whether guiding principles for the proceeding should be adopted and if so, whether the following are appropriate: affordability, transparency, equity, efficiency, and support for electrification;

(5) Whether the Commission should modify any prior Commission-adopted Climate Credit objectives, definitions, and rules; and

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5 *California Community Choice Association's Comments on the Order Instituting Rulemaking to Improve the California Climate Credit*, R.25-07-013 (Sept. 26, 2025) (CalCCA OIR Comments).

6 *California Community Choice Association's Reply Comments on the Order Instituting Rulemaking to Improve the California Climate Credit*, R.25-07-013 (Oct. 13, 2025) (CalCCA OIR Reply Comments).

7 R.25-07-13, PHC Transcript (Nov. 21, 2025) (PHC Transcript).

8 Assembly Bill 1207 (Irwin, Chapter 117, Statutes of 2025).

(6) Whether implementing the changes adopted in this proceeding will lead to increased costs for the utilities.

CalCCA also has no additional comments on its support for the OIR's categorization of the proceeding as quasi-legislative.[9]

This Post-PHC Statement addresses the following schedule issues that were introduced at the PHC: (1) whether the Commission should consider phasing the proceeding, with a Phase 1A to immediately change the timing of the fall distribution of the Climate Credit from October to August or September to address affordability during peak periods, prior to addressing all other issues starting in Phase 1B related to timing and eligibility for the Climate Credit; and (2) what processes should be incorporated into the schedule to consider all scoped issues.

As set forth below, CalCCA makes the following recommendations:

- Reject the recommendation for a Phase 1A to immediately consider only modifying the timing of Climate Credit distribution, and instead in Phase 1 consider all issues concerning Climate Credit distribution timing simultaneously to ensure all Californians are considered;
- Utilize standard proceeding processes to develop the record; and
- Develop a data tool to allow parties to assess bill impacts of proposals.

II. THE RECOMMENDATION FOR A PHASE 1A TO IMMEDIATELY CONSIDER ONLY MODIFYING THE TIMING OF CLIMATE CREDIT DISTRIBUTION SHOULD BE REJECTED IN FAVOR OF A REVIEW IN PHASE 1 OF ALL POTENTIAL MODIFICATIONS TO THE CLIMATE CREDIT TO ENSURE ALL CALIFORNIANS ARE CONSIDERED

While CalCCA supports phasing of the proceeding, given the multitude of issues that will need to be addressed, overall issues regarding timing and eligibility for distribution of the Climate Credit should be addressed simultaneously to ensure all Californians are considered. ALJ Sotero requests parties to comment on whether an expedited Phase 1A is necessary to

9 *See* CalCCA OIR Opening Comments, at 4.

immediately consider changing the timing of the fall Climate Credit distribution from October to the summer peaking months of August or September. This is presumably to address high energy bills experienced by some customers living in very hot climate zones. Phase 1A may also include legal briefing on changing the timing, as well as other requirements of Public Utilities Section 748.5. The Commission would then consider in Phase 1B whether to make broader changes not only to the timing of distribution, but also to eligibility and other issues impacting who receives the Climate Credit and when.

CalCCA opposes immediately making changes in a Phase 1A to only timing of the Climate Credit distribution. For the reasons set forth below, the Commission should consider all timing and eligibility issues simultaneously and carefully to ensure the record gets adequately developed to understand the impacts of all changes on all Californians, and to prevent customer confusion of multiple changes.

First, the impacts of moving up the fall 2026 Climate Credit from October to August or September on all customers are currently unknown. As CalCCA noted in its OIR Reply Comments, optimal timing to support bill affordability with the Climate Credit may depend on the climate zone in which a customer lives.[10] Customers living in winter peaking time zones, which exist in California, may be negatively impacted by moving the Climate Credit distribution to August or September. Additionally, questions of optimal timing are intertwined with eligibility in that both have impacts on how much bill relief any given customer will receive.[11]

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10 *See* CalCCA OIR Reply Comments, at 6.

11 *Ibid*.

The decision to modify timing should not be made hastily without sufficient time to model impacts and develop the record.[12]

Second, rushing a modification to the Climate Credit without establishing an outreach plan, followed by potential subsequent changes to the Climate Credit, could lead to unnecessary customer confusion. The Commission should also reject San Diego Gas & Electric Company's recommendation during the PHC that relaxing the timing and procedure for customer notifications (such as was done during COVID) should be considered given the affordability crisis.[13] Adequate customer notifications of Climate Credit changes are critical to ensure customers understand where the Climate Credit came from, and how it is being distributed.

Instead, parties should immediately dive into a fulsome Phase 1 that considers issues in the following order: (1) guiding principles to frame Climate Credit issues and priorities; (2) legal briefing on issues related to PHC Discussion Question 3;[14] and (3) simultaneously considering eligibility, timing, frequency, and customer communications, including examining customer bill impacts from any changes. This will ensure time is taken to simultaneously consider the impacts of proposed changes and that any modifications adopted provide maximum support and transparency to customers. After Phase 1, a subsequent phase can address implementation of any necessary changes based on revised regulations from CARB to comply with AB 1207, and other issues.

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12 Indeed, Pacific Gas and Electric Company (PG&E) stated during the PHC that a decision on timing would need to be made by March 2026 to allow changes to the distribution timing to occur in fall 2026. *See* PHC Transcript, at 52. There is simply not adequate time for the Commission to develop an adequate record to support such an important decision.

13 *See* PHC Transcript, at 55.

14 *Agenda for Prehearing Conference in R.25-07-013,* R.25-07-013 (Nov. 2, 2025).

III. THE COMMISSION SHOULD CONSIDER BOTH THE USE OF STANDARD PROCEEDING PROCESSES TO DEVELOP THE RECORD AND DEVELOP A DATA TOOL TO ALLOW PARTIES TO DETERMINE THE BILL IMPACTS OF PROPOSALS

To create a strong record in this proceeding, the Commission should consider using standard processes, including but not limited to staff reports, workshops, and rulings requesting comments, in addition to developing a data tool to allow for standardized modeling of bill impacts of proposals. As is normal Commission practice, facilitating comments from parties through workshops, staff reports, and rulings will allow all stakeholders to provide their perspectives. To further strengthen the record and ensure the Climate Credit is optimized as intended, the Commission should develop a data tool to standardize how parties consider the impacts of proposals to modify the Climate Credit, as recommended in CalCCA's OIR Comments. A standardized set of outputs from a tool such as this could ensure like-for-like comparisons of proposals.

IV. CONCLUSION

This concludes CalCCA's Post-Prehearing Conference Statement. CalCCA appreciates the Commission's time and effort in resolving this proceeding.

Respectfully submitted,

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

December 8, 2025

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

Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future.	R.21-06-017

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON PACIFIC GAS AND ELECTRIC COMPANY'S, SAN DIEGO GAS & ELECTRIC COMPANY'S, AND SOUTHERN CALIFORNIA EDISON COMPANY'S DRAFT ELECTRIFICATION IMPACT STUDY PART 2 REPORTS

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

December 15, 2025

TABLE OF CONTENTS

SUMMARY OF RECOMMENDATIONS[1]

CalCCA recommends that the IOUs include the following modifications in their final EIS

Part 2 Reports:

- The IOUs should refine the assumptions used in the demand flexibility scenarios to inform strategies to achieve greater distribution grid cost reductions;
- The IOUs should refine their mitigation assumptions to ensure they are realistic, achievable, and consider potential costs to customers, as set forth below:
  - SCE should revise its program participation assumptions for the Alternative Demand Flexibility scenario to reflect realistic and attainable levels;
  - SCE should revise its Base Case assumption that adds too much flexibility, including to the TE charging shape that goes beyond the existing TOU rates;
  - PG&E should revise its assumptions for L1 and L2 EV charging participation in dynamic pricing programs;
  - PG&E should reassess its assumptions for new transformers on the secondary system; and
  - PG&E should update its Enhanced Demand Flexibility scenario to not assume perfect orchestration.
- The IOUs should provide greater clarity and maintain consistent assumptions for their Base Case mitigations;
- SCE and SDG&E should include the estimated distribution rate impacts of electrification load growth; and
- SCE and SDG&E should include descriptions of their plans for improving their methodologies for modeling the secondary system.

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

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

Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future.	R.21-06-017

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON PACIFIC GAS AND ELECTRIC COMPANY'S, SAN DIEGO GAS & ELECTRIC COMPANY'S, AND SOUTHERN CALIFORNIA EDISON COMPANY'S DRAFT ELECTRIFICATION IMPACT STUDY PART 2 DRAFT REPORTS

California Community Choice Association[2] (CALCCA) submits comments on Pacific Gas and Electric Company's (PG&E), San Diego Gas & Electric Company's (SDG&E), and Southern California Edison Company's (SCE) (collectively, the investor-owned utilities (IOUs)), draft Electrification Impact Study (EIS) Part 2 Reports (Draft Reports).[3] These comments are filed in response to Administrative Law Judge Jack Chang's email of Monday, December 8, 2025, that clarifies that comments on the Draft Reports, due on December 15, 2025, must be e-filed into the R.21-06-017 docket and served to the current service list for R.21-06-017.

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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] *See Pacific Gas and Electric Company's (U 39 E) Draft Electrification Impact Study Part 2*, Rulemaking (R.) 21-06-017 (Oct. 31, 2025); *San Diego Gas & Electric Company's (U 902 E) Draft Electrification Impact Study Part 2*, R.21-06-017 (Oct. 31, 2025); *Southern California Edison Company's (U 338-E) Electrification Impacts Study Part 2 Draft Report*, R.21-06-017 (Oct. 31, 2025).

I. INTRODUCTION

The IOUs' final EIS Part 2 Reports will inform the strategic integration of load management and demand flexibility into the distribution planning processes under various scenarios. Given California's current rate affordability crisis and the anticipated growth of electrification, grid capacity must be optimized, and the need for costly upgrades must be reduced. The Draft Reports present the IOUs' first analysis of the potential costs and benefits of load management and demand flexibility to meet this objective.

CalCCA appreciates the efforts of each of the IOUs in preparing the Draft Reports. Each of the IOUs undertook a different approach in the Draft Reports, resulting in varying estimates of demand flexibility opportunities and cost savings. PG&E provided the most detailed assessment of the impacts on the secondary distribution grid, using a methodology developed in-house. SCE took a different approach by modeling demand flexibility down to the circuit level and disaggregating it to the secondary system. However, SCE did not conduct a granular analysis of infrastructure needs on the secondary system, unlike PG&E's analysis. SDG&E similarly used simplified assumptions to determine demand flexibility and growth impacts, as well as mitigations to offset the need for distribution upgrades.

CalCCA recommends the IOUs include the following modifications in their final EIS Part 2 Reports:

- The IOUs should refine the assumptions used in the demand flexibility scenarios to inform strategies to achieve greater distribution grid cost reductions;
- The IOUs should refine their mitigation assumptions to ensure they are realistic, achievable, and consider potential costs to customers, as set forth below:
    - SCE should revise its program participation assumptions for the Alternative Demand Flexibility scenario to reflect realistic and attainable levels;

- SCE should revise its Base Case assumption that adds too much flexibility, including to the Transportation Electrification (TE) charging shape that goes beyond the existing time-of-use (TOU) rates;
- PG&E should revise its assumptions for Level 1 (L1) and Level 2 (L2) Electric Vehicle (EV) charging participation in dynamic pricing programs;
- PG&E should reassess its assumptions for new transformers on the secondary system; and
- PG&E should update its Enhanced Demand Flexibility scenario to not assume perfect orchestration.

- The IOUs should provide greater clarity and maintain consistent assumptions for their Base Case mitigations;
- SCE and SDG&E should include the estimated distribution rate impacts of electrification load growth; and
- SCE and SDG&E should include descriptions of their plans for improving their methodologies for modeling the secondary system.

II. THE IOUS SHOULD REFINE THE ASSUMPTIONS USED IN THE DEMAND FLEXIBILITY SCENARIOS TO INFORM strategies to achieve GREATER DISTRIBUTION GRID COST REDUCTIONS

The IOUs should refine their assumptions and perform additional sensitivity analyses for each of the Draft Reports to inform distribution planning strategies that can achieve greater system benefits and cost reductions. One of the primary objectives of the EIS Part 2 Reports is to identify the preliminary potential value of mitigating distribution upgrades driven by the rapid growth of electrification through the targeted adoption of distributed energy resources (DER) and load flexibility.[4] This expansion of electrification is occurring at a time when California is already experiencing a crisis in rate affordability. Since distribution system costs are a large and growing cost component of electricity rates,[5] the IOUs must be diligent in identifying assumptions,

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4 *EIS -Part 2, Draft Results Presentation Workshop* (EIS Workshop) (Nov. 19, 2025), video recording, at 6:46: https://www.youtube.com/watch?v=CXvD2Nv7pz8.

5 California Energy Commission, *2024 California Electric and Gas Utility Costs Report, AB 67 Annual Report to the Governor and Legislature* (Sept. 2025), at 21-22: https://www.cpuc.ca.gov/AB67Report.

limitations of the study, and potential mitigation measures to offset potential rate increases. While the IOUs' Draft Reports represent a preliminary assessment, additional work is necessary to ensure the reports are transparent about real-world limitations so that cost reductions are more likely to be achieved through enhanced distribution planning.

PG&E's and SCE's demand flexibility scenarios demonstrate only modest cost savings compared to their base case scenarios. The cumulative base case costs shown in PG&E's Draft Report were $25.5 billion in 2040, compared to $23.7 billion in the Enhanced Demand Flexibility scenario for the same year. This amounts to a cost reduction of $1.8 billion, or seven percent. SCE's Draft Report showed a cumulative Base Case cost of $13.2 billion by 2040, compared to $12.9 billion for its Initial Demand Flexibility scenario and approximately $11.8 billion for its Alternative Demand Flexibility scenario. This represents a cost reduction of $320 million, or 2.4 percent, for its Initial Demand Flexibility scenario, and $1.4 billion, or 10.4 percent, for its Alternative Demand Flexibility scenario.

While SDG&E's Draft Report showed cost savings of almost 23 percent between its Base Case and Demand Flexibility scenario, it characterized the Draft Report as "conceptual" and employed a simplified modeling approach.[6] SDG&E further stated that it "did not independently undertake an investigation to identify any specific load management programs that could be leveraged to fulfill" the "potential for reduced infrastructure needs through strategic load management."[7] For this reason, SDG&E should be required to reexamine its assumptions and study methodologies to fully leverage the potential of demand flexibility.

In addition, both SCE and SDG&E downplayed the near-term potential for demand flexibility to offset the need for grid upgrades in the Draft Reports. SCE stated that "demand

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6 SDG&E Draft Report, at 4.

7 *Id*. at 1.

flexibility may not yet be a dependable substitute for traditional infrastructure solutions and highlights the need for further validation before integration into the distribution planning process."[8] SDG&E casts doubt on the usefulness of the Equity and Demand Flexibility scenarios, viewing them instead as "hypothetical "what if" situations that carry little weight in terms of anticipating the infrastructure that will be needed to meet future, real world needs."[9]

Demand flexibility could offer significant potential for mitigating the need for grid upgrades. The challenge facing the IOUs is to balance the need for cost-effective and reliable demand flexibility measures with the urgent need to address affordability, in the context of rapid electrification. Rather than dismissing the potential for demand flexibility to reduce the need for grid upgrades, the IOUs should instead focus on expediting and expanding the use of demand flexibility, including implementing pilots to validate its reliability and cost-effectiveness.

III. THE IOUS SHOULD REFINE THEIR MITIGATION ASSUMPTIONS TO ENSURE THEY ARE REALISTIC, ACHIEVABLE, AND CONSIDER POTENTIAL COSTS TO CUSTOMERS

The IOUs should reexamine and refine their demand flexibility assumptions to ensure they are realistic, achievable, and consider the potential customer costs associated with the measure. Decision (D.) 24-10-030 established that the EIS Part 2 Reports "should produce learnings that translate into improvements" for the IOUs' Distribution Planning and Execution Processes.[10] Using unrealistic assumptions will not produce credible results to inform distribution planning, however. In fact, ignoring the cost impacts on customers may lead to overly optimistic estimates of demand flexibility adoption rates and undermine the real benefits of demand flexibility.

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8 SCE Draft Report, at 21.

9 SDG&E Draft Report, at 28.

10 D.24-10-030, *Decision Adopting Improvements to Distribution Planning and Project Execution Process, Distribution Resource Planning Data Portals, and Integration Capacity Analysis Maps,* R.21-06-017 (Oct. 23, 2024), at 97: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M544/K154/544154869.PDF.

While adjusting the assumptions to be more realistic and achievable may result in reduced cost savings between the base and demand flexibility cases, the results of the final EIS Part 2 Reports must be reliable and achievable. This should not be construed to mean that the IOUs should not aggressively pursue means of expanding reliance on demand flexibility to mitigate the need for distribution investments, as explained in Section II of these Comments. Rather, this is consistent with the recommendation for the IOUs to refine and improve upon the initial results from the Draft Reports to validate the reliability and cost-effectiveness of demand flexibility.

Instead, the IOUs should implement the following refinements, as set forth below:

(1) SCE should revise its program participation assumptions for the Alternative Demand Flexibility Scenario to reflect realistic and attainable levels;

(2) SCE should revise its Base Case assumption that adds too much flexibility, including to the TE charging shape that goes beyond the existing TOU rates;

(3) PG&E should revise its assumptions to include both L1 and L2 EV charging participation in dynamic pricing programs;

(4) PG&E should reassess its assumptions for new transformers on the secondary system; and

(5) PG&E should update its Enhanced Demand Flexibility scenario to not assume perfect orchestration.

A. SCE Should Revise Its Program Participation Assumptions for the Alternative Demand Flexibility Scenario to Reflect Realistic and Attainable Levels

SCE's Alternative Demand Flexibility scenario assumes 100 percent participation rates for EVs and energy storage, rationalizing this assumption as a "theoretical bound to assess the maximum potential of demand flexibility" for these technologies.[11] In response to comments from Energy Division (ED) staff during the November 20, 2025, EIS Workshop, SCE stated that this assumption stemmed from ED's finding that the Initial Demand Flexibility scenario seemed to

[11] SCE Draft Report, at 11.

reflect business-as-usual.[12] A 100 percent demand flexibility participation rate is not a reliable planning assumption and should be revised to reflect levels that are both realistic and attainable. If SCE's program participation assumptions are not revised to reflect realistic and attainable participation levels, SCE's report would likely reflect over-investment, resulting in distorted levels of underperformance and cost inefficiencies.

B. SCE Should Revise its Base Case Assumption that Adds Too Much Flexibility, Including to the TE Charging Shape that Goes Beyond the Existing TOU Rates

SCE stated in the EIS Workshop discussion of its demand flexibility results that it added too much flexibility to its TE charging load shape by imposing flexibility from TOU rates that go beyond the existing TOU rates in its Base Case. SCE also stated that it is committed to correcting this mistake in future distribution planning processes.[13] This error reduced the cost savings between the Base Case and Initial Demand Flexibility scenarios, but the total impact was not clear from the discussion. SCE should either modify the Base Case to remove the additional demand flexibility or include a description of the error and potential impacts in the narrative about the scenarios.

C. PG&E Should Revise Its Assumptions to Include Both L1 and L2 EV Charging Participation in Dynamic Pricing Programs

PG&E should revise its assumptions for dynamic pricing response to incorporate both L1 and L2 EV charging. PG&E's Draft Report makes unrealistic assumptions about customer adoption of L2 home EV charging for its Enhanced Demand Flexibility Scenario, assuming only home L2 charging will respond to dynamic pricing. The Draft Report provides estimates of home L2 chargers available to shift loads to periods of low dynamic pricing.[14] This assumption overlooks the high

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[12] EIS Workshop (Nov. 20, 2025), video recording, at 1:08:27: https://www.youtube.com/watch?v=aQ9yWlDMGFU.

[13] *Id.*, at 35:40 and 1:20:00.

[14] PG&E Draft Report, at 71.

costs for customers to upgrade their residential service panels to accommodate L2 charging, which could deter participation in future dynamic pricing programs.

Rather than focusing exclusively on L2 chargers for responding to dynamic pricing signals, PG&E should revise its assumption to also include L1 charging. While this may reduce the cost savings relative to L2 charging, the lower cost of L1 chargers could result in greater overall participation in dynamic pricing programs, providing a more realistic assumption based on consumer behavior.

As an example, Peninsula Clean Energy (PCE) conducted a study of 'right-sizing' transportation electrification to support its EV Ready incentive program for EV charging for multifamily housing, workplaces, and public parking.[15] The study found that L1 chargers can meet the needs of nearly all commuters at significantly lower costs, while enabling more charger installations than would be possible otherwise. This right-sizing approach, which uses devices specifically sized to meet customer needs, eliminates the need for service upsizing and avoids costly distribution upgrades.

D. PG&E Should Reassess Its Assumptions for New Transformers on the Secondary System

PG&E employed a fundamentally different approach from the other IOUs in the Draft Report for estimating the need for new or replacement transformers on the secondary system, which resulted in a $12.5 billion estimate for new transformers to serve new loads. In response to questions from The Public Advocates Office at the California Public Utilities Commission (Cal Advocates) about the results of the secondary system analysis, PG&E stated that it would further investigate its

[15] PCE, *Commute and multi-family EV Charging Needs Analysis: Level 1 or Level 2 Power Managed Charging Meets the Daily Needs of 94+% of Drivers*: https://www.peninsulacleanenergy.com/wp-content/uploads/2021/09/Determining-the-Appropriate-Level-of-Power-Sharing-for-EV-Charging-in-Multifamily-Properties.pdf.

assumptions.[16] PG&E should reassess and refine its methodology for determining the number of new and replacement transformers on the secondary system and include the results of its investigation in its final EIS Part 2 Report.

E. PG&E Should Update Its Enhanced Demand Flexibility Scenario to Not Assume Perfect Orchestration

PG&E's Enhanced Demand Flexibility scenario analyzed grid constraints on the secondary system and assumed coordinated management, or orchestration, of demand flexibility to alleviate those constraints. This very granular approach optimizes the responses of individual measures (*e.g.,* EV charging, energy storage, heat pumps), but it should be clearly identified as a theoretical approach that has not been demonstrated at scale. Assuming perfectly or highly coordinated responses from these resources is an overly optimistic confidence assumption that ignores the potential that some of them may not respond to pricing or dispatch signals, for instance, which overstates the benefits of orchestration. PG&E should provide additional detail about its orchestration assumptions, including the assumed constructs between PG&E, CCAs, and third parties, and should not assume perfect or overly high coordination of resources.

IV. THE IOUS SHOULD PROVIDE GREATER CLARITY AND MAINTAIN CONSISTENT ASSUMPTIONS FOR THEIR BASE CASE MITIGATIONS

The Draft Reports should be modified to provide greater clarity into the Base Case mitigation measures and to establish consistent assumptions for their Base Cases. The Base Case scenario should reflect a business-as-usual foundation upon which the equity and demand flexibility scenarios are built. Including mitigations beyond business-as-usual in the Base Case makes it difficult to assess the effectiveness of demand flexibility. Applying consistent mitigation assumptions in the Base Case ensures comparability of results across the IOUs.

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16 EIS Workshop, at 4:08:00.

Both PG&E and SCE incorporated mitigation measures in their Base Cases but did not provide sufficient detail regarding those assumptions to enable a clear comparison with the demand flexibility scenario. PG&E describes its Base Case as mitigated, "meaning that distribution engineers developed low-cost solutions where feasible (*e.g.,* load transfers) and load profiles incorporated existing and future customer behaviors (*e.g.,* evolving TOU rates)."[17] SCE's Draft Report includes tables detailing the total number of mitigation projects, which are capital investments in distribution grid upgrades and new equipment, but do not include details for any non-capital-related mitigation measures.[18] SDG&E describes its Base Case as business-as-usual and appears to rely solely on the energy consumption forecast from the 2023 Integrated Energy Policy Report, without additional mitigation.[19]

The IOUs should provide details about the assumptions used in their Base Cases, as they serve as the foundation for evaluating the results of the other scenarios. The IOUs should also align the assumptions for their Base Cases to the extent possible, enabling a comparison of the effectiveness of the mitigation measures across the IOUs and supporting fair and equal treatment of all customers.

V. SCE AND SDG&E SHOULD INCLUDE THE ESTIMATED DISTRIBUTION RATE IMPACTS OF ELECTRIFICATION LOAD GROWTH

SCE and SDG&E should perform analyses of the estimated distribution rate impacts of electrification, similar to PG&E's analysis in its Draft Report. PG&E's assessment of the potential effects of electrification demonstrated downward pressure on the distribution component of electric rates. The analysis was not intended to forecast electric rates, but rather, to highlight the potential benefits of electrification on utility rates. Requiring SCE and SDG&E to perform a similar analysis could further inform the California Public Utilities Commission's (Commission) expectations for the

17 PG&E Draft Report, at 37.
18 SCE Draft Report, at 7.
19 SDG&E Draft Report, at 5-6.

range of possible downward pressure on distribution rate and help quantify the potential savings related to electrification growth in each service territory.

VI. SCE AND SDG&E SHOULD INCLUDE DESCRIPTIONS OF THEIR PLANS FOR IMPROVING THEIR METHODOLOGIES FOR MODELING THE SECONDARY SYSTEM

SCE's and SDG&E's EIS Part 2 Reports should include descriptions of plans for improving their methodologies for modeling the impacts of electrification and DER growth on the secondary system. PG&E's Draft Report includes an innovative and detailed analysis of the effects of electrification on the secondary system. The methodology PG&E developed enabled it to enhance the accuracy of its secondary system modeling, allowing for more detailed assumptions for new or upgraded transformers to serve new loads. While it is unreasonable to expect either SCE or SDG&E to develop or adopt a similar framework for their final EIS Part 2 reports, due January 28, 2026, they should each include a discussion of future enhancements for modeling secondary system impacts and costs to better inform future distribution planning efforts.

VII. CONCLUSION

For all the foregoing reasons, CalCCA respectfully requests consideration of the comments herein by the Commissions and the IOUs in their final EIS Reports 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

December 15, 2025

Comments on Final Discussion Paper

Initiative: Demand and distributed energy market integration

Comment period

Nov 26, 2025, 10:00 am - Dec 17, 2025, 05:00 pm

Submitting organizations

California Community Choice Association

California Community Choice Association

Submitted on 12/17/2025, 01:22 pm

Contact

Lauren Carr (lauren@cal-cca.org)

1. Please provide your feedback on the demand and distributed energy market integration final discussion paper.

The California Community Choice Association (CalCCA) appreciates the opportunity to comment on the topics and problem statements in the California Independent System Operator's (CAISO) Demand and Distributed Energy Market Integration (DDEMI) Final Discussion Paper (Discussion Paper).[1] The comments herein recommend modifications to the Distributed Energy Resource Aggregation (DERA) problem statements, methods for assessing stakeholders' prioritization of problem statements, and CalCCA's priorities related to the Performance Evaluation Methodology (PEM), Economic Demand Response (DR) Participation model, and DERA problem statements. The comments also describe how the CAISO should incorporate the demand-side bidding topic into the initiative. In summary, the CAISO should:

Modify the DERA problem statement assessment to address the need for coordinated development of a DERA Resource Adequacy (RA) pathway with the California Public Utilities Commission (CPUC);

Broaden the DERA problem statement to address concerns about separate resources at a single site participating in separate aggregations as they apply across participation models and program administrators;

Prioritize the Economic DR Participation, PEM, and DERA participation topics within the DDEMI initiative:

- Enhance the proxy demand resource (PDR) model used for Economic DR participation to provide behind-the-meter (BTM) resources with the ability to export in the short term;
- Develop and vet new PEMs that can better reflect evolving market needs in the short term;
- In coordination with the CPUC, develop an RA pathway for DERAs in the medium-term using lessons learned from implementing the modified PDR (mPDR) RA rules;

- Continue to explore the challenges and opportunities of individual BTM device-level measurement in the short term;
- Seek to reduce the significant administrative and cost barriers created by metering requirements on each individual resource within an aggregation; and

Explore demand-side bidding in parallel with the problem statements to ensure solutions developed for PEMs, exports, and other topics support the eventual addition of demand-side bidding.

[1] References herein to the terms "topics" and "problem statements" may differ from those used in the Discussion Paper. In these comments, 'topics' refers to the six issue areas identified in the Discussion Paper and 'problem statements' refer to the 31 statements associated with these issue areas.

2. Please provide your feedback on the ISO assessment on the Distributed Energy Resource (DER) problem statement assessment.

CalCCA generally supports the six problem statements for the DERA market participation model, but reiterates its November 6, 2025, comments on the October 16, 2025, Working Group Session 10: [1][2]

> *First*, the inability to provide resource adequacy (RA) is one of the primary barriers to Distributed Energy Resource (DER) expansion. CalCCA agrees that the lack of a pathway for DERAs to qualify for RA must be addressed at both the CAISO and the CPUC. However, the problem statement implies that the actions of the CAISO and the CPUC must be sequenced to resolve the RA counting issue. While the CAISO and the CPUC each have separate jurisdictional responsibilities regarding the qualification of DERAs for RA, activities to modify these processes should occur in coordination, rather than sequentially, to continue the momentum on improvements necessary to expand DERA participation.
>
> *Second*, the concern about separate resources at a single site participating in separate aggregations applies to the conflicting operations of DERs enrolled in any market participation model, as well as to DER participation in wholesale and retail markets. In addition, the problem statement states that "utilities may be concerned that the battery operation for DERA participation impacts the other program." These concerns extend beyond just utilities and their programs. Other aggregators, including CCAs and third-party entities, will be affected by this issue.

CalCCA's October 16, 2025, comments provide recommendations on how to revise the problem statements to incorporate these changes, including modified language, redlines, and strikethrough.[3]

[1] CalCCA interprets this question to reference the six problem statements for the DERA topic discussed during Working Group Session 10 on October 16, 2025.

[2] *See CalCCA Comments on the October 16, 2025, Working Group Session 10* (Nov. 6, 2025): https://stakeholdercenter.caiso.com/Comments/AllComments/2f80e46e-e576-427a-b671-f2a9b4ae390a#org-61be003b-121c-49f3-a381-f6094b7105a1.

[3] *Ibid.*

3. Please share your thoughts on how CAISO should prioritize or scope future policy

development for this initiative. The ISO is interested in your top five problem statements and how they should be sequenced in the short-term (2026-2027), mid-term (2028-2030), and long-term (2030+), and to the extent possible, discuss any anticipated benefits to market efficiency or system reliability.

The Discussion Paper includes six topics and 31 problem statements within these topics. The CAISO asks stakeholders to identify their top five highest-priority problem statements. When evaluating stakeholders' priority problem statements, the CAISO should consider key linkages among problem statements, as identified by CalCCA below, and the breadth and diversity of stakeholder alignment on these problem statements to determine next steps.

The CAISO should prioritize the Economic DR Participation, PEM, and DERA topics within the DDEMI initiative. Enhancements to the Economic DR Participation models will enable the participation of more price-responsive demand that can offer reliability benefits through participation in the RA program *and* bid economically into the market to respond to price signals. The CAISO's existing PEMs should be improved to more accurately assess the performance of emerging DR programs, including those with BTM batteries and electric vehicle chargers. The DERA model is currently underutilized due to the inability to provide RA capacity. It could be better utilized if the CAISO and the CPUC developed a pathway to provide RA capacity.

Within these topic areas, CalCCA's highest priority problem statements are:

1. Topic 4/Problem Statement 1: "While PDR is the most compatible CAISO model for BTM-interconnected storage, because it is conceptualized as load curtailment, it does not include any measured export of energy from individual locations to measure performance of the resource via any of existing PEMs—including MGO—so that BTM storage aggregations cannot offer the full resource capability, and PDR performance is artificially capped at levels reflecting conservative estimates of site load, resulting in significant energy from BTM storage that is unused during events and unavailable to the CAISO market."

CalCCA's highest priority within this initiative is enhancing the PDR model used for Economic DR Participation to provide BTM resources using the PDR model with the ability to export. Allowing PDR exports will accurately reflect resource capabilities, minimize barriers to participation, and offer both reliability and cost-efficiency benefits. Expanding the pool of dependable capacity able to participate using the PDR model will unlock additional available capacity able to provide reliability value during times of system stress and improve price formation by increasing the amount of demand that can respond to market price signals. For these reasons, CalCCA supports evaluating an mPDR model to more accurately reflect the capabilities of PDR resources that can export.

The CAISO should address PDR exports in the short term. Addressing this issue in the short term would align the timing of this initiative with the CPUC's recently opened DR (R.25-09-004) and RA (R.25-10-003) proceedings, in which many stakeholders, including CalCCA,[1] asked the CPUC to develop a qualifying capacity (QC) methodology for PDRs capable of exports. RA participation necessitates both a QC methodology and a market participation model. The CAISO and CPUC should coordinate to ensure that both entities address the issues within their separate jurisdictional responsibilities, thereby supporting full RA and energy market participation of PDRs with export capabilities.

2. Topic 1/Problem Statement 2: "Existing Performance Evaluation Methodologies (PEM), such as the commonly used 5-in-10 and 10-in-10 approaches, are not well suited for emerging DR participation (inclusive of all technology types such as Behind-the-meter batteries, aggregations, Electric Vehicle charging, etc.) whose frequent dispatching distorts baseline calculations."

The existing PEMs create a high barrier to entry for non-investor-owned utility load-serving entities and program operators, including community choice aggregators, and do not adequately support the participation of DERs, like BTM batteries and electric vehicles (EVs), in CAISO markets. Simplifying and improving the accuracy of the baseline methodologies can help promote market diversity and competition and accelerate the integration of clean resources that support state policy goals and overall market efficiency. Along with the development of an mPDR model, the PEMs will also need to be updated to measure exported energy. This initiative should seek to develop, and vet new PEMs that can better reflect evolving market needs than the existing PEMs, especially given that many existing PEMs are underutilized, indicating these PEMs may not be suitable for the types of programs participating in the CAISO markets.

Relatedly, CalCCA supports the CAISO's ability to adjust PEM details without tariff changes to keep pace with evolving programs and market needs, as articulated in Topic 1/Problem Statement 4. CalCCA also supports improvements to the control group PEM and modifications to the registration requirements that could increase the use of the control group PEM, as documented in Topic 1/Problem Statement 5. While CalCCA supports this problem statement, it is concerned that the control group methodology may not be scalable without other modifications that address challenges beyond registration requirements. Should this problem statement be scoped into the initiative, the CAISO should therefore allow for the exploration of additional modifications related to the control group PEM.

The CAISO should address PEM issues in the short term, given their high priority and the ability to reach resolution on them quickly relative to the other high priority problem statements.

3. Topic 5/Problem Statement 3: "There is currently no pathway for DER aggregations (DERAs) to qualify for resource adequacy, and this is a multi-agency issue needing CAISO's attention because CAISO would need to address or help resolve some issues (including deliverability determination and visibility) before the CPUC would develop a Qualifying Capacity methodology, as well as because CAISO needs to develop Net Qualifying Capacity methodologies."

As described in Section 2 above, the inability to provide RA is one of the primary barriers to DER expansion. CalCCA encourages continuing the momentum on improvements necessary to expand DERA participation through participation in the RA program. The CAISO and the CPUC should coordinate while undertaking the tasks necessary within their jurisdictional responsibilities to allow DERAs to provide RA.

The inability to provide RA is a barrier to DERs seeking to provide exports through the PDR model or participate through the DERA model. The CAISO, in coordination with the CPUC, should first seek to develop a mechanism for DR exports to obtain RA using the mPDR model in the short term, as discussed above, as the PDR model is the more widely used and more accessible model. The CAISO should then develop an RA pathway for DERAs in the medium-term using lessons learned from implementing the mPDR RA rules.

4. Topic 1/Problem Statement 3: "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 currently recognized in developing PEM baselines, the baselines could potentially undervalue the BTM device-level's 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. CalCCA therefore supports the continued exploration of device-level measurement to better understand its challenges and opportunities.

The CAISO should address this problem statement in the short term, given the expected proliferation of BTM devices and the potential impact on the grid. This creates an urgent need for greater visibility into the performance (and expected future performance) of BTM resources to ensure safe and reliable grid operations.

5. Topic 4/Problem Statement 2: "Current metering requirements for PDR restrict the ability to use device-level metering. Requiring revenue-grade meters (with ANSI C12) on each individual resource within an aggregation creates significant administrative and cost barriers."

CalCCA agrees with the problem statement that requiring revenue-grade meters on each individual resource within an aggregation creates significant administrative and cost barriers. These barriers will restrict the ability to use the device-level measurement described in Topic 1/Problem Statement 3, above. To ensure proper measurement of BTM devices' contribution to load reduction and provide visibility into their performance and forecasted performance, the CAISO should seek to reduce such barriers.

Addressing this problem statement is a necessary factor in exploring the implementation of device-level measurement, should the CAISO move forward as a result of the exploration of Topic 1/Problem Statement 3 described above. As such, the CAISO should seek to address this problem statement in the short term, along with Topic 1/Problem Statement 3.

Topic 6 - Expanding Demand-Side Bidding

In addition to the ranked problem statements above, the CAISO should continue to explore the Expanding Demand-Side Bidding topic within this initiative. As the CAISO notes in the Discussion Paper, demand-side bidding can "expand participation, strengthen price responsiveness, and enable new approaches to load management, all while preserving market integrity and reliability."[2]

The implementation of demand-side bidding is likely a long-term endeavor given its transformational impact on the market and potential complexity. By prioritizing this topic now, the CAISO and stakeholders can ensure that more immediate DDEMI reforms (*e.g.,* modifications to PEMs and enhancements to the PDR model to allow exports) are aimed towards aligning the market and DER participation models with a two-sided system that allows for demand-side bidding. The CAISO should therefore explore demand-side bidding in parallel with the above problem statements to ensure solutions developed for PEMs, exports, and other topics support the eventual addition of demand-side bidding.

[1] *See California Community Choice Association's Reply Comments on the Order Instituting Rulemaking to Enhance Demand Response in California*, R.25-09-004 (Dec. 1, 2025) at 11-12: https://cal-cca.org/wp-content/uploads/2025/12/Reply-Comments-on-the-OIR-to-Enhance-Demand-Response-in-California-12-01-25.pdf.

[2] Discussion Paper, at 26.

Comments on Final Discussion Paper

Initiative: Demand and distributed energy market integration

Comment period

Nov 26, 2025, 10:00 am - Dec 17, 2025, 05:00 pm

Submitting organizations

MCE

MCE

Submitted on 12/17/2025, 04:59 pm

Contact

Jordyn Bishop (jbishop@mceCleanEnergy.org)

1. Please provide your feedback on the demand and distributed energy market integration final discussion paper.

Marin Clean Energy (MCE) appreciates the opportunity to comment on the Final Discussion Paper (Discussion Paper). MCE thanks the California Independent System Operator (CAISO) for launching and prioritizing the Demand and Distributed Energy Market Integration (DDEMI) working group, and for giving stakeholders the opportunity to help shape the policy vision on how demand and distributed energy resources can participate in the market.

Overall, the Discussion Paper successfully captures the working group's efforts and the stakeholder-identified problem statements. As this initiative moves forward, MCE recommends the CAISO:

- Provide greater specificity in the Issue Paper to help stakeholders meaningfully engage during policy development, including clear objectives, market design considerations, and the potential policy pathways forward.
- Prioritize targeted reforms to the proxy demand resource (PDR) model and performance evaluation methodologies (PEMs) in the near-term, while advancing demand-side bidding as the longer-term policy direction.
- Implement near-term pilots with independent measurement and verification to demonstrate the efficacy of modified PDR and PEM proposals and include the necessary details in the Issue Paper.

2. Please provide your feedback on the ISO assessment on the Distributed Energy Resource (DER) problem statement assessment.

Many of the Distributed Energy Resource Aggregation (DERA) problem statements reflect structural challenges with the current participation model, rather than distinct issues that can be addressed through incremental or near-term reforms. Resolving these challenges comprehensively requires a fundamental reworking of the DERA model. This effort would consume significant stakeholder and CAISO resources, with unclear outcomes. Given the DDEMI initiative's scope and timeline, **MCE encourages the CAISO to prioritize targeted policy development opportunities in the near-term (including PDR and PEM reforms), while advancing demand-side bidding as the longer-term policy direction.**

3. Please share your thoughts on how CAISO should prioritize or scope future policy development for this initiative. The ISO is interested in your top five problem statements and how they should be sequenced in the short-term (2026-2027), mid-term (2028-2030), and long-term (2030+), and to the extent possible, discuss any anticipated benefits to market efficiency or system reliability.

MCE recommends that the CAISO prioritize the following PDR and PEM problem statements for policy development:

1. Problem Statement 4.1 – Short-term Priority

   While PDR is the most compatible CAISO model for BTM-interconnected storage, because it is conceptualized as load curtailment, it does not include any measured export of energy from individual locations to measure performance of the resource via any of existing PEMs—including MGO—so that BTM storage aggregations cannot offer the full resource capability, and PDR performance is artificially capped at levels reflecting conservative estimates of site load, resulting in significant energy from BTM storage that is unused during events and unavailable to the CAISO market.

2. Problem Statement 1.5 – Short-term Priority

   Registration Requirement for control group end users to be registered in the Demand Response System limits use of non-participating end users within a control group and is in conflict with consumer data privacy rules.

3. Problem Statement 1.2 – Short-term Priority

   Existing PEMs, such as the commonly used 5-in-10 and 10-in-10 approaches, are not well suited for emerging DR participation (inclusive of all technology types such as Behind-the-meter batteries, aggregations, Electric Vehicle charging, etc.) whose frequent dispatching distorts baseline calculations.

4. Problem Statement 4.2 – Mid-term Priority

   Current metering requirements for PDR restrict the ability to use device-level metering. Requiring revenue-grade meters (with ANSI C12) on each individual resource within an aggregation creates significant administrative and cost barriers.

5. Problem Statement 4.3 – Long-term Priority

   Current bidding rules prevent PDR from being able to reflect costs in the market when the costs are greater than the soft energy bid cap of $1,000/MWh. This results in inefficient use of the PDR resources and does not provide equitable treatment relative to all other resources that are able to reflect costs greater than $1,000/MWh.

PDR Problem Statements – 4.1, 4.2, and 4.3

MCE encourages the CAISO to prioritize the PDR problem statements in a sequential manner that reflects both reform feasibility and overall system value.

Problem Statement 4.1 should be prioritized in the short term because, as the CAISO's initial assessment notes, reforms could be straightforward in terms of policy considerations and relatively low in terms of implementation needs. Resolving the export limitation in the near term would improve market efficiency by allowing PDR resources to more accurately reflect their full operational capabilities. Enabling more complete utilization of existing BTM storage resources would also strengthen reliability given the broader pool of flexible resources that would be capable of responding to grid conditions.

Problem Statement 4.2 should be prioritized in the mid-term because, as the CAISO's initial assessment notes, metering accuracy standards for PDR are aligned with local regulatory authority (LRA) requirements, so reforms will require LRA coordination. While coordination requires sufficient time, DER participation in CAISO markets is currently limited by strict metering accuracy standards. Working to enable alternative accuracy standards would improve market efficiency by allowing aggregations to scale more efficiently.

MCE also encourages the CAISO to reframe Problem Statement 4.2 to state:

> "Current metering accuracy standards and utility meter data latency create significant administrative and cost barriers and constrain DER participation in CAISO markets."

Problem Statement 4.3 should be prioritized in the long-term because, as the CAISO's initial assessment notes, this issue raises more complex challenges including the need for standardized opportunity cost definitions, more data visibility, and new verification and settlement structures. However, eventually addressing these issues would ultimately improve market efficiency by allowing PDR resources to more accurately reflect their costs.

MCE encourages the CAISO to implement pilots with independent measurement and verification to demonstrate the efficacy of modified PDR proposals before formal tariff or BPM changes, and to include the necessary details in the Issue Paper.

PEM Problem Statements – 1.2 and 1.5

Problem Statements 1.2 and 1.5 should be prioritized in the short term. Existing PEMs need refinement to support emerging DER deployment and strategies. Reducing barriers for emerging DERs is critical for improving market efficiency, and for unlocking broader DER participation in CAISO markets. The control group methodology can yield more accurate outputs and reduce exogenous distortions to customer baseline calculations, but its use is constrained by the requirement to register non-participant accounts for "matched" control groups. Together, these reforms can be addressed in the short term, which would provide a strong foundation for exploring more complex demand-side market reforms.

MCE encourages the CAISO to implement pilots with independent measurement and verification to demonstrate the efficacy of proposals for new or modified PEMs before formal tariff or BPM changes, and to include the necessary details in the Issue Paper.

Topic 6 - Expanding Demand-Side Bidding

In addition to the ranked statements listed above, **MCE strongly encourages the ISO to explicitly prioritize Expanding Demand-Side Bidding as a strategic guidepost informing all future policy design and development under the DDEMI initiative.**

While MCE recognizes that the introduction of demand-side bidding is a complex undertaking, prioritizing this concept now will help ensure that more immediate DDEMI reforms are aimed towards transforming the market to reflect a balanced, two-sided system. Exploring demand-side bidding in parallel with the above problem statements would help direct the right incremental solutions to both PEMs and the PDR models.

As the CAISO's initial assessment notes, demand-side bidding can expand DER participation, enhance system efficiency, and enable innovative load management strategies. For DER aggregations, the ability to optimize both import and export in response to price signals and system conditions is foundational to scaling cost-effective demand flexibility. Enabling bidirectional capability would also strengthen system reliability by allowing DER portfolios to dynamically respond to grid conditions.

Attachments

12.17.25 MCE Comments on Final Discussion Paper.docx