Regulatory Filings

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Oversight of Electric Integrated Resource Planning and Procurement Processes.	R.25-06-019

CALIFORNIA COMMUNITY CHOICE ASSOCIATION REPLY COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENTS ON ELECTRICITY PORTFOLIOS FOR THE 2027-2028 TRANSMISSION PLANNING PROCESS AND POTENTIAL FOR GEOGRAPHICALLY-TARGETED PROCUREMENT

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SUMMARY OF RECOMMENDATIONS[1]

The Commission should:

- Differentiate load forecast scenarios by their intended use as set forth below, recognizing SCE's point that long-lead-time transmission planning should consider a more forward-looking range of potential load growth than forecasts used for other purposes:
    - Use the 2025 IEPR forecast for the base case as recommended by AReM and CalCCA in Opening Comments, given it is the most up-to-date forecast of anticipated load growth and demonstrates that existing interim GHG targets are achievable under more realistic load growth assumptions; and
    - Use the 2024 IEPR forecast as a sensitivity only to identify proactive, least-regrets transmission solutions that provide value across a range of plausible futures;
- Develop portfolios that prioritize "least-regrets" transmission solutions that remain useful as load and resource assumptions change to address concerns from CAISO and SCE about delayed infrastructure development and unintended consequences; and
- Refrain from adopting location-specific procurement requirements for the Western LA Basin until the Commission and CAISO have sufficiently evaluated the full range of feasible and cost-effective wires and non-wires alternatives, as recommended by Cal Advocates, PG&E, SCE, and SDG&E.

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

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California Community Choice Association[2] (CalCCA) submits these reply comments pursuant to the *Administrative Law Judge's Ruling Seeking Comments on Electricity Portfolios for the 2027-2028 Transmission Planning Process and Potential for Geographically-Targeted Procurement*[3] (Ruling), dated August 31, 2026.

I. INTRODUCTION

Party Opening Comments demonstrate broad recognition of the uncertainty facing California's resource and transmission planning processes as load forecasts, resource costs, resource availability, and deliverability estimates continue to evolve.[4] This uncertainty

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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, 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, Valley Clean Energy, and WestLight Energy.

[3] *Administrative Law Judge's Ruling Seeking Comments on Electricity Portfolios for the 2027-2028 Transmission Planning Process and Potential for Geographically-Targeted Procurement*, Rulemaking (R.) 25-06-019 (Aug. 31, 2026), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M616/K589/616589361.PDF.

[4] References herein to "Opening Comments" refer to those filed on or about September 28, 2026, in R.25-06-019 in response to the Ruling.

underscores the need for a planning approach that accounts for the different goals and timelines of resource procurement and transmission development, and also preserves flexibility to respond to changing conditions.

CalCCA agrees with recommendations of Southern California Edison Company (SCE) that long-lead-time transmission planning should consider a more forward-looking range of potential load growth than forecasts used for other purposes.[5] CalCCA also agrees with the Alliance for Retail Energy Markets (AReM) that the California Public Utilities Commission (Commission) should use the 2025 Integrated Energy Policy Report (IEPR) forecast for the base case, rather than the 2024 IEPR forecast, consistent with CalCCA's Opening Comments.[6] To balance the need for realistic build rates in the base case, and proactive transmission planning for future needs, the Commission should limit use of the 2024 IEPR forecast to the sensitivity case.

Further, the Commission should develop portfolios that prioritize "least-regrets" transmission solutions that remain useful as load and resource assumptions change to address concerns from the California Independent System Operator (CAISO) and SCE about delayed infrastructure development and unintended consequences.[7] The Commission's portfolios should enable transmission planning decisions to account for a broad range of plausible future load and resource scenarios to ensure new resources can be interconnected to serve load in a reliable and cost-effective manner.

In addition, CalCCA agrees with parties that state it is premature to adopt location-specific procurement requirements for the Western LA Basin without additional analysis of the

5 *See* SCE Opening Comments, at 3.
6 *See* AReM Opening Comments, at 2-3, CalCCA Opening Comments, at 9-10.
7 *See* CAISO Opening Comments, at 2; SCE Opening Comments, at 13.

costs, benefits, and feasibility of both wires and non-wires alternatives.[8] Before imposing a location-specific procurement requirement, the Commission and the CAISO should evaluate the full range of potential solutions. This evaluation should assess each alternative's feasibility, cost, development timeline, land-use constraints, storage charging capability, interconnection availability, market competitiveness, and other relevant benefits and constraints.

Taken together, these approaches best maintain California's commitment to addressing climate change with rigorous greenhouse gas (GHG) targets by focusing on the long-term need for diverse resources, such as clean firm generation and high-capacity factor wind. They do so by grounding the portfolios in more current and realistic assumptions about future load growth, resulting in more feasible near-term build rates. The Commission should maintain its rigorous carbon targets and develop portfolios that will inform a Transmission Plan to relieve current constraints on transmission, interconnection, and project availability.

Overall, these reply comments recommend steps to help the Commission manage uncertainty without delaying infrastructure likely needed to meet California's long-term reliability and policy objectives or prematurely imposing procurement costs on customers that ultimately prove unnecessary or uneconomic. In summary, the Commission should:

- Differentiate load forecast scenarios by their intended use as set forth below, recognizing SCE's point that long-lead-time transmission planning should consider a more forward-looking range of potential load growth than forecasts used for other purposes:
    - Use the 2025 IEPR forecast for the base case as recommended by AReM and CalCCA in Opening Comments, given it is the most up-to-date forecast of anticipated load growth and demonstrates that existing interim GHG targets are achievable under more realistic load growth assumptions; and

[8] *See* The Public Advocates Office of the California Public Utilities Commission (Cal Advocates) Opening Comments, at 29-31; Pacific Gas and Electric Company (PG&E) Opening Comments, at 14-19; SCE Opening Comments, at 16-21; San Diego Gas and Electric (SDG&E) Opening Comments at 10-11.

    - Use the 2024 IEPR forecast as a sensitivity only to identify proactive, least-regrets transmission solutions that provide value across a range of plausible futures;

- Develop portfolios that prioritize "least-regrets" transmission solutions that remain useful as load and resource assumptions change to address concerns from CAISO and SCE about delayed infrastructure development and unintended consequences; and

- Refrain from adopting location-specific procurement requirements for the Western LA Basin until the Commission and CAISO have sufficiently evaluated the full range of feasible and cost-effective wires and non-wires alternatives, as recommended by Cal Advocates, PG&E, SCE, and SDG&E.

II. LOAD FORECASTS SHOULD BE DIFFERENTIATED BY THEIR INTENDED USE BECAUSE AS STATED BY SCE, LONG-LEAD-TIME TRANSMISSION PLANNING SHOULD CONSIDER A MORE FORWARD-LOOKING RANGE OF POTENTIAL LOAD GROWTH THAN FORECASTS USED FOR OTHER PURPOSES

Opening Comments demonstrate the need for the Commission to differentiate among load forecast scenarios based on the decision the forecast is intended to inform and the lead time associated with that decision. A single forecast likely no longer serves resource procurement, transmission planning, and other planning purposes when those decisions involve different timelines, risks, and consequences of forecast error.

SCE and SDG&E identify the Single Forecast Agreement as a potential constraint on incorporating the 2025 IEPR Forecast into the Integrated Resource Planning (IRP) process.[9] Recent volatility in load forecasts—particularly from large-load interconnection applications, energization assumptions, and transportation electrification—underscores why the joint agencies and CAISO should not allow the Single Forecast Agreement to prevent selection of the IEPR forecast best suited to a particular planning purpose.

For transmission planning, the Commission should use a more forward-looking load outlook that appropriately accounts for plausible future load growth. Transmission projects

[9] *See* SCE Opening Comments, at 10; SDG&E Opening Comments, at 6.

require long development timelines, and insufficient transmission infrastructure is already constraining access to resources. Waiting for uncertain load to reach the level of certainty appropriate for a procurement obligation before planning the transmission needed to serve that load risks perpetuating these constraints.

SCE's comments emphasize the need to make transmission planning more proactive and forward-looking. SCE explains that "insufficient progress on the transmission infrastructure needed to access those resources has continued to constrain their availability for procurement and planning."[10] SCE urges the Commission to avoid repeating this cycle by "aggressively accelerat[ing] transmission projects that provide access to high-value wind, geothermal, and enhanced geothermal resources and maintain optionality for future development, even when those resources are not yet contracted or reflected in procurement plans."[11] SCE therefore recommends that the Preferred System Plan reflect realistic near- and mid-term assumptions while the Transmission Planning Process (TPP) uses a more forward-looking portfolio. CalCCA agrees with SCE's general distinction that long-lead-time transmission planning should consider a more forward-looking range of potential load growth than forecasts used for other purposes.

Accordingly, the Commission should differentiate load forecasts by use case rather than assume that the same forecast scenario is appropriate for every planning decision. While the following sections focus on the load forecasts appropriate for the base and sensitivity cases used in the TPP, it is also important to consider the load forecasts used for resource procurement. Before ordering procurement, the Commission should closely consider when procurement is needed, the confidence that uncertain loads will materialize, the development status of large loads, and the load-serving entity (LSE) responsible for serving that load. CalCCA proposed

[10] SCE Opening Comments, at 3.
[11] *Id.*

mechanisms for doing so in its August 14, 2026, comments on the Reliable and Clean Power Procurement Program.[12] This distinction will allow California to plan infrastructure early enough to preserve future options without prematurely imposing procurement costs on customers for load that may not materialize.

A. AReM's and CalCCA's Recommendation to Use the 2025 IEPR Forecast for the Base Case Should be Adopted As It Is the Most Current And Demonstrates That Existing Interim GHG Targets Are Achievable

The Commission should use the 2025 IEPR forecast for the base case, as recommended by AReM and CalCCA in Opening Comments,[13] because it is the most recently available forecast based on the most current information about sources of load growth. Further, the resulting portfolios based on the 2025 IEPR reflect achievable build rates, demonstrating that the current GHG targets are achievable and do not need to be relaxed under more realistic load growth assumptions.

Some parties support relaxing the interim GHG targets in the base case to achieve realistic resource build rates.[14] CalCCA agrees that portfolio build rates should be feasible, but its analysis in Opening Comments demonstrates that this objective can be achieved without relaxing the interim GHG targets by using a more realistic load forecast in its modeling. The Commission should therefore use the 2025 IEPR forecast for the base case, as AReM

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[12] *See California Community Choice Association's Comments on Administrative Law Judge's Ruling Seeking Comments on Additional Proposal for a Reliable and Clean Power Procurement Program*, R.20-05-003 (Aug. 14, 2026) at 33-34, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M615/K005/615005837.PDF.

[13] AReM Opening Comments, at 2-3; CalCCA Opening Comments, at 9-10.

[14] *See* Middle River Power, LLC Opening Comments, at 2; PG&E Opening Comments, at 2; SCE Opening Comments, at 2; SDG&E Opening Comments, at 6; and the Western Power Trading Forum Opening Comments, at 3.

recommends,[15] and limit use of the 2024 IEPR forecast to the sensitivity case, while retaining the existing GHG targets in both cases.

B. The 2024 IEPR Forecast Should Be Used in the Sensitivity Case to Identify Least-Regrets Transmission Solutions

While CalCCA generally supports using the most current available forecast for planning decisions, CalCCA agrees with SCE that long-lead-time transmission planning should be more proactive and forward looking.[16] Using the 2025 IEPR forecast for the base case and only relying on the 2024 IEPR for the sensitivity case strikes the right balance between realistic load growth assumptions and proactive transmission planning that supports a range of future outcomes.

Analysis of the sensitivity case using the 2024 IEPR should not be treated merely as a fact-finding exercise. It should provide the Commission and CAISO with a meaningful opportunity to identify transmission investments that perform well across different plausible futures, one with load growth more consistent with the 2025 IEPR and another with more significant load growth. As AReM observes, the sensitivity case may provide important information regarding transmission development from a least-regrets perspective.[17] To obtain this important information, a base case grounded in realistic load growth assumptions and resource build rates should be complemented with a more ambitious sensitivity case to reveal which transmission solutions support both cases.

Where the sensitivity identifies transmission needs beyond those identified in the base case, the Commission should encourage the CAISO to evaluate whether potential upgrades will provide long-term benefits across multiple scenarios. This analysis should consider whether an upgrade can address both base- and sensitivity-case needs, increase access to diverse resources,

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15 AReM Opening Comments, at 2-3.
16 *See* SCE Opening Comments, at 3.
17 *See* AReM Opening Comments, at 5.

provide additional deliverability or reliability benefits, and/or preserve valuable options under plausible future load growth. Such projects may represent prudent investments even when the precise resource or load assumptions driving the sensitivity remain uncertain.

III. TRANSMISSION SOLUTIONS THAT ARE ROBUST ACROSS A RANGE OF PLAUSIBLE FUTURES SHOULD BE PRIORITIZED TO ADDRESS CAISO'S AND SCE'S CONCERNS ABOUT INFRASTRUCTURE DELAYS AND UNINTENDED CONSEQUENCES

The CAISO's and SCE's Opening Comments further demonstrate the importance of evaluating transmission needs across multiple scenarios rather than optimizing the transmission system around a single portfolio. In addition to an uncertain load forecast, technology cost and availability are uncertain, pointing to the need for transmission solutions that are robust across a range of plausible futures. The CAISO explains that changes in this portfolio relative to previous cycles' portfolios can compound uncertainty for resource and transmission planning and ultimately delay infrastructure needed for reliability.[18] This reinforces the value of identifying transmission investments that remain useful as load and resource assumptions change.

SCE raises a similar concern regarding potential "unintended consequences" of removing offshore wind from the Base Case. SCE states that the Commission and CAISO should "carefully evaluate any unintended consequences associated with removing offshore wind from the Base Case portfolio."[19] SCE also recommends "assess[ing] whether removing offshore wind from the Base Case portfolio affects the benefits, utilization, or need for previously approved transmission facilities and whether those facilities could instead support other generation resources, reliability objectives, or future resource development opportunities."[20] CalCCA supports SCE's recommended review, as it will help ensure changes in offshore wind

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18 *See* CAISO Opening Comments, at 2.
19 SCE Opening Comments, at 13.
20 *Id.*

assumptions do not inadvertently limit development of other resources, impede reliability in the Humboldt area, or change deliverability allocations already provided to in-development projects.

To further address the concerns expressed by the CAISO and SCE, the Commission should encourage the CAISO to use the base *and* sensitivity portfolios to identify proactive, least-regrets transmission solutions that perform well across a range of plausible futures. This approach can reduce the risk that changes in load or resource assumptions repeatedly delay needed transmission, while also protecting customers by prioritizing investments with durable benefits rather than infrastructure dependent on a single uncertain forecast outcome.

IV. RECOMMENDATIONS BY CAL ADVOCATES, PG&E, SCE, AND SDG&E THAT THE COMMISSION REFRAIN FROM ADOPTING LOCATION-SPECIFIC PROCUREMENT REQUIREMENTS FOR THE WESTERN LA BASIN SHOULD BE ADOPTED

The Commission should refrain from adopting location-specific procurement requirements for the Western LA Basin, as noted in Opening Comments of Cal Advocates, PG&E, SCE, and SDG&E. These parties demonstrate that it will be premature to do so before completing additional analysis of the alternatives available to address the identified reliability need.[21] As stated by PG&E, no demonstration has been made that such a procurement order is: (1) not duplicative with other Commission-ordered procurement; (2) demonstrably cost-effective relative to alternative solutions; or (3) feasible to implement within the required timeframe.[22]

Despite insufficient evidence to demonstrate that a procurement order is the most cost-effective and viable solution, the CAISO recommends a procurement order for 2,405 megawatts or 12,075 megawatt hours to be online by the second quarter of 2032 to address "a two-year gap

[21] *See* Cal Advocates Opening Comments, at 29-31; PG&E Opening Comments, at 14-19; SCE Opening Comments, at 16-21; and SDG&E Opening Comments at 10-11.
[22] *See* PG&E Opening Comments, at 14.

between the identified 2032 reliability need and the availability of the transmission solution."[23] PG&E estimates that this solution could cost up to $4.9 billion, compared with a new and fourth transformer (*i.e.*, Wires Alternative 1) at $106 million to $126 million.[24] The CAISO recommendation constitutes a significant expense that has not been demonstrated to be feasible at meeting the identified short-term need. In addition, SCE states that the volume of storage necessary to meet the need "cannot be brought online at [the relevant] substations within [the necessary] timeframe" due to limits imposed by "[i]nterconnection capacity, substation capability, land availability, and permitting and construction timelines in a densely developed and geographically-constrained area."[25]

Before imposing a location-specific procurement requirement, the Commission and the CAISO should ensure that the full range of potential solutions has been evaluated, including transmission upgrades, storage, generation, and other feasible wires and non-wires alternatives. That evaluation should consider the feasibility, cost, development timeline, land-use constraints, ability of storage resources to charge, interconnection availability, market competitiveness, and other relevant benefits and constraints associated with each alternative. Parties have long called for Commission and CAISO coordination to develop a process for evaluating wires and non-wires alternatives for local reliability needs and reducing reliance on emitting resources in local areas. Despite including this issue in the scope of the IRP proceeding,[26] the Commission has continually delayed such work. The Commission should not continue to ignore this pressing need by rushing to issue a procurement order that may be infeasible and uneconomic.

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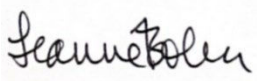
23 CAISO Opening Comments, at 9-10.
24 PG&E Opening Comments, at 17.
25 SCE Opening Comments, at 16.
26 *See Assigned Commissioner's Scoping Memo and Ruling*, R.25-06-019 (Oct. 28, 2025) at 8-9, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M585/K485/585485746.PDF.

Moreover, additional process is necessary to address the many implementation questions prior to issuing a geographically specific procurement order. For example, wires and non-wires solutions impact LSE cost responsibility differently. As noted by SDG&E, "[w]hile the cost of a wires solution would be allocated to every customer on the CAISO grid, a geographically-targeted procurement order would assign the same cost *solely* to the customers of the LSE(s) subject to the procurement order."[27] This shift in cost responsibility onto a smaller pool of entities, and impacts from other implementation questions such as LSE procurement responsibility, cost containment measures, rate and bill impacts and others, must be more fully evaluated with parties before a procurement order is issued.

V. CONCLUSION

CalCCA respectfully requests consideration of the recommendations herein.

Respectfully submitted,



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[27] SDG&E Opening Comments, at 10-11 (emphasis in original).

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future.	R.21-06-017

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION ADOPTING AN APPLICATION PROCESS FOR UTILITY DISTRIBUTED ENERGY RESOURCES ORCHESTRATION AND ORDERING UTILITIES TO INCORPORATE LOAD FLEXIBILITY SCENARIOS INTO THEIR DISTRIBUTION PLANNING AND EXECUTION PROCESSES

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SUMMARY OF RECOMMENDATIONS[1]

CalCCA recommends that the Proposed Decision be modified to:

- Address the scoped issues of IOU conflicts of interest and potential market power concerning grid investments versus demand flexibility solutions as required by sections 1701.1 and 1701.5;
- Adopt CalCCA's six guiding principles on conflict of interest and market power concerns to inform the working group's efforts;
- Extend Track 2 of the proceeding for the duration of the proposed working group process, with Energy Division hiring a consultant (rather than the IOUs) to facilitate the working group process;
- Split the Track 2 working group process into two consecutive phases:
    - Phase 1 will address the conflict of interest and market power issues and governance and oversight rules, including through an evaluation of lessons learned from jurisdictions where demand flexibility markets have been successfully deployed. Phase 1 will culminate in a report, formal party comments, and a Commission decision establishing the governance and oversight rules to be incorporated into the Phase 2 orchestration framework;
    - Phase 2 will address the orchestration framework, culminating in a consultant report to be submitted to the record of this proceeding or as envisioned in the Proposed Decision, to the successor application proceeding.
- If the Commission fails to adopt CalCCA's recommendations, it should, at a minimum, acknowledge in the Proposed Decision's findings and conclusions the existence of IOU conflicts of interest and potential market power concerns and establish the need and venue to address these issues.

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

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CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION ADOPTING AN APPLICATION PROCESS FOR UTILITY DISTRIBUTED ENERGY RESOURCES ORCHESTRATION AND ORDERING UTILITIES TO INCORPORATE LOAD FLEXIBILITY SCENARIOS INTO THEIR DISTRIBUTION PLANNING AND EXECUTION PROCESSES

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 Adopting an Application Process for Utility Distributed Energy Resources Orchestration and Ordering Utilities to Incorporate Load Flexibility Scenarios into Their Distribution Planning and Execution Processes*[4] (Proposed Decision or PD), dated September 25, 2026; and Administrative Law Judge Jack Chang's procedural email dated October 6, 2026, clarifying the date for party opening and reply comments.

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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, 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, Valley Clean Energy, and WestLight 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 Adopting an Application Process for Utility Distributed Energy Resources Orchestration and Ordering Utilities to Incorporate Load Flexibility Scenarios into Their Distribution Planning and Execution Processes*, Rulemaking (R.) 21-06-017, (Sept. 25, 2026), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M620/K524/620524441.PDF.

I. INTRODUCTION

The PD takes meaningful steps towards establishing an application framework for investor-owned utility (IOU)[5] orchestration of distributed energy resources (DER) and incorporating load flexibility into the distribution planning and execution process (DPEP). It directs a working group series, facilitated by the IOUs' consultant, to develop the application framework, resulting in a report to be included with the IOUs' Joint Application for a DER orchestration framework (Joint IOU Application). CalCCA appreciates the PD's adoption of initial guiding principles for IOU distribution system operator (DSO)-led orchestration, and its direction to refine those principles through a working group process.

The PD nevertheless leaves a critical gap: the guiding principles and directives to the working group fail to address the IOUs' inherent conflicts of interest in DSO orchestration, their potential to exercise market power, or the governance and oversight safeguards needed to address those concerns. These omissions are despite the Order Instituting Rulemaking (OIR) and the 2021 Scoping Memo expressly placing the conflict of interest and market power concerns within the scope of this proceeding.[6] In fact, the recent Amended Scoping Memo assigned the role of DSO to the IOUs and highlighted potential market power concerns, but neglected to address the conflict of interest issues raised in the OIR and the 2021 Scoping Memo.[7] CalCCA's Response[8] to the Motion of the Center for Biological Diversity (CBD) and Utility Consumer Action Network (UCAN)[9] to Address Unaddressed Issues (*i.e.*, the conflict of interest issue) addresses the need for the Commission to address these

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[5] As used herein, "IOUs" refer collectively to Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE).

[6] *See Order Instituting Rulemaking to Modernize the Electric Grid for a High DER Future* (OIR), R.21-06-017 (July 2, 2021), at 10-12, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M390/K664/390664433.PDF; *see also Assigned Commissioner's Scoping Memo and Ruling*, R.21-06-017 (Nov. 15, 2021) (2021 Scoping Memo), at 6, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M422/K949/422949772.PDF.

[7] *Assigned Commissioner's Amended Scoping Memo and Ruling* (Amended Scoping Memo), R.21-06-017 (Aug. 11, 2023), at 6, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M516/K786/516786462.PDF.

[8] *CalCCA's Response to Center for Biological Diversity Utility Consumer's Action Network Motion to Address Unaddressed Issues* (Response), R.21-06-017 (Sep. 25, 2026), at 4-6, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M620/K720/620720792.PDF

[9] *CBD UCAN Motion to Address Unaddressed Issues* (Motion), R.21-06-017 (Sep. 10, 2026), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M617/K649/617649890.PDF.

unresolved *scoped issues* consistent with California Public Utilities Code[10] sections 1701.1 and 1701.5.

While the IOUs have statutory authority to operate the distribution system and to propose mechanisms for deploying cost-effective DER programs, incentives, and tariffs pursuant to sections 399.2 and 769, respectively, neither section expressly grants the IOUs blanket authority to dispatch customer-owned DERs. The Commission should therefore consider DER orchestration separately from the IOUs' authority to operate the distribution grid. This distinction is important because any orchestration of customer-owned DERs could enable the deferral or avoidance of conventional utility capital investments. This orchestration of DERs, therefore, may contradict the IOUs' financial incentives under the existing regulatory model, in which they earn an authorized rate of return on their capital investments. As the Commission recognized in the OIR and the 2021 Scoping Memo, these circumstances raise material conflict of interest and market power concerns that must be addressed before the orchestration framework is established.

The Commission should, therefore, establish governance and oversight rules *before* the Joint IOU Application is submitted. The Proposed Decision authorizes the IOUs to hire a consultant to facilitate an informal series of working groups and to prepare a report to be submitted as an attachment to the proposed Joint IOU Application. This gives the IOUs substantial control over the process for developing a framework that could shape their own authority, the participation rules for third-party providers, and the evaluation of DERs as alternatives to grid upgrades. Governance and oversight are therefore threshold issues that should be in place prior to the Joint IOU Application to ensure DER orchestration maximizes ratepayer benefits, facilitates nondiscriminatory participation, and accounts for avoided capital investments. Developing governance and oversight rules *in parallel with* the DER orchestration framework risks embedding IOU economic and institutional preferences into the framework's architecture and operating rules before the Commission has established adequate safeguards. Correcting these potential deficiencies after the fact would likely be more difficult and costly.

The Commission should therefore modify the PD to enable a structured process to ensure these issues are addressed. *First,* the PD should adopt CalCCA's proposed guiding principles addressing the conflict of interest issues to provide guidance during the working group process and beyond. *Second,*

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

Track 2 of the proceeding should be extended for the duration of the working group process, with Energy Division hiring a consultant (rather than the IOUs) to facilitate the working group. *Third,* the working group process should be split into two phases. Phase 1 should address the conflict of interest and market power concerns identified in the OIR, allowing Energy Division and the parties to discuss how to address these issues through proposed governance and oversight rules that will serve as the basis for the common DER orchestration framework. Phase 1 will include a consultant report, formal party comments on the record, and a Commission decision on the governance and oversight rules. Phase 2 should begin after Phase 1 is complete, with Energy Division and the consultant facilitating the working group in establishing a DSO framework. Phase 2 will culminate in a consultant's report to be submitted to the record of this proceeding or as envisioned in the PD, to the successor application proceeding.

If the Commission fails to adopt the recommendations contained herein, it should, *at a minimum*, acknowledge the conflicts of interest and market power concerns raised in the OIR and 2021 Scoping Memo in the Proposed Decision's findings and conclusions. Failure to do so violates sections 1701.1 and 1701.5 and risks undermining confidence in the adopted framework and diminishing potential ratepayer benefits.

In summary, CalCCA recommends that the Commission modify the PD to:

- Address the scoped issues of IOU conflicts of interest and potential market power concerning grid investments versus demand flexibility solutions as required by sections 1701.1 and 1701.5;
- Adopt CalCCA's six guiding principles on conflict of interest and market power concerns to inform the working group's efforts;
- Extend Track 2 of the proceeding for the duration of the proposed working group process, with Energy Division hiring a consultant (rather than the IOUs) to facilitate the working group process;
- Split the Track 2 working group process into two consecutive phases:
    - Phase 1 will address the conflicts of interest and market power issues and governance and oversight rules, including through an evaluation of lessons learned from jurisdictions where demand flexibility markets have been successfully deployed. Phase 1 will culminate in a report, formal party comments, and a Commission decision establishing the governance and oversight rules to be incorporated into the Phase 2 orchestration framework;
    - Phase 2 will address the orchestration framework, culminating in a consultant report to be submitted to the record of this proceeding or as envisioned in the Proposed Decision, to the successor application proceeding.

- If the Commission fails to adopt CalCCA's recommendations, it should, at a minimum, acknowledge in the Proposed Decision's findings and conclusions the existence of IOU conflicts of interest and potential market power concerns and establish and the venue to address these issues.

II. FAILURE TO ADDRESS SCOPED ISSUES ON THE IOU CONFLICTS OF INTEREST CONCERNING GRID INVESTMENTS VERSUS DEMAND FLEXIBILITY SOLUTIONS VIOLATES SECTIONS 1701.1 AND 1701.5

Section 1701.5 requires the Commission to "issue by order or ruling a scoping memo that describes the issues to be considered and the applicable timetable for resolution . . . ." Section 1701.5 states that the Commission "shall resolve the issues raised in the scoping memo within 18 months of the date the proceeding is initiated . . . ." If the Commission is unable to meet that deadline, section 1701.5 requires it to "make[] a written determination that the deadline cannot be met, including findings as to the reason, and issue[] an order extending the deadline."

As noted in caselaw interpreting these scoping memo requirements, "[i]dentifying the issues under consideration facilitates informed participation—including presentation of arguments and evidence—by those who may have a stake in the resolution of those issues."[11] The court went on to state that "[i]f the Commission cannot fairly be said to have complied with the statutory scoping memo requirement, it has failed to regularly pursue its authority."[12] The Commission cannot simply ignore issues that have been scoped into the proceeding.[13]

The OIR recognized that existing IOU cost-recovery structures focus on large capital investment and that increased DER deployment could reduce IOU rates of return.[14] The OIR further recognized that, "[f]or an IOU-administered DSO to be successful, performance incentives not tied to capital investments may be needed, or there may be a need for a third-party DSO administrator."[15]

The 2021 Scoping Memo[16] placed this issue at the center of Track 2 by directing consideration of alternative DSO models and limits on market power:

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11 *Golden State Water Co. v. Public Utils. Comm'n* (2024) 15 Cal.5th 380, 394-395.

12 *Ibid.*

13 *See Southern California Edison Co. v. Pub. Utils. Comm'n* (2006) 140 Cal.App.4th 1085, at 1106-07 (Commission's failure to comply with its scoping memo constitutes reversible error if the failure to do so was prejudicial); *see also Bullseye Telecom, Inc. v. California Pub. Utils. Comm'n* (2021) 66 Cal.App.5th 301, 324 (even if the Commission deviates from the Scoping Memo, petitioner must show that the deviation was significant or that it was prejudiced by it).

14 *OIR,* at 11.

15 *Id*. at 11-12.

16 2021 Scoping Memo, at 6.

> How do alternative DSO models compare in their ability to plan and operate a high DER grid, unlock economic opportunities for DERs to provide grid services, limit market power, reduce ratepayer costs, increase equity, support grid resiliency, and meet State policy objectives?[17]

The 2021 Scoping Memo also asked whether the IOUs should be "incentivized to cost-effectively prepare for widespread DER deployments."[18] The Amended Scoping Memo, however, narrowed Track 2 by *presuming* that the IOUs would serve as DSOs, but kept limits on IOU market power within the scope of the proceeding.[19] It also included in scope the gaps, barriers, and solutions to meet the operational requirements for operating the grid with high DER penetration, while omitting the investigation of alternative DSO models and IOU incentives for cost-effectively integrating DERs.[20]

IOUs own and operate the distribution infrastructure on which they earn a rate of return. Orchestrating customer- and third-party-owned DERs is distinct from an IOU's traditional function of maintaining and operating the distribution grid. Under an IOU-led DSO model, the IOUs will determine distribution system needs at specific locations on the grid, control critical system information, and may administer or participate in programs, markets, or other mechanisms through which DERs compete with traditional utility investment. DER orchestration therefore gives IOUs influence over which resources may participate, how they are dispatched, what service they provide, how they are compensated, and whether they may be used to defer or avoid IOU investments. IOUs under the IOU-led DSO model can also exert market power over customer- and third-party-owned DER because they have real-time and forecast data and operational visibility into the grid that is not available to non-IOU entities. Since IOUs earn authorized returns on capital investments, potentially including IOU-owned DER, they have an inherent bias against procuring demand flexibility services from customers or third-party aggregators.

As noted above, the OIR identified concerns regarding the IOU conflict of interest and market power and correctly scoped them into the proceeding. The 2021 Scoping Memo reinforced the importance of addressing these concerns by calling for an evaluation of alternative DSO business models. While the Amended Scoping Memo recognized the market power issue, it assigned the IOUs the role of DSOs without adequately addressing conflicts of interest or market power issues. By

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17 *Id.*
18 *Ibid.*
19 Amended Scoping Memo, at 6.
20 *Ibid.*

designating the IOUs as DSOs without resolving these concerns, the Commission failed to address: (i) the need for protection against IOU exertion of market power; (ii) the need for guardrails to ensure competitive neutrality; and (iii) the evaluation of mechanisms to maximize DER participation. Designating the IOUs to perform the DSO function as the starting point for determining a DER orchestration framework makes resolving these issues more, not less, important.

The Commission should not close Track 2 of this proceeding before identifying and resolving outstanding governance and market power issues scoped into the OIR, as required by sections 1701.1 and 1701.5. The Commission should instead modify the PD to address these issues in the working group process, to be held during an extended Track 2 of this proceeding.

III. THE PD SHOULD BE MODIFIED TO ADDRESS CONCERNS ABOUT GOVERNANCE AND OVERSIGHT OF AN IOU-LED DER ORCHESTRATION FRAMEWORK

The PD should be modified to address unresolved issues regarding the scoped IOU conflict of interest between grid investments and demand flexibility solutions, including those raised in the Motion. The PD errs in failing to address the governance and oversight issues *prior to* the submission of the Joint IOU Application, which risks allowing the IOUs to embed their economic and institutional imperatives into the DSO framework. The PD should be modified to address these concerns, by:

- Adopting the six additional guiding principles proposed by CalCCA to address competitive neutrality and oversight
- Extending Track 2 for the duration of the working group series;
- Requiring Energy Division, rather than the IOUs, to retain a consultant to lead the working group series; and
- Beginning the working group series with a Phase 1 focusing on establishing rules for governance and oversight of the DER orchestration framework, culminating in a report, formal party comments, and a Commission decision; and
- Following the Phase 1 working group (Phase 1 WG) with a Phase 2 developing the DER orchestration framework, culminating with a report to either be submitted in the record of the proceeding or attached to the Joint IOU Application.

A. The Six Additional Guiding Principles Proposed by CalCCA Should Be Adopted

The PD should be modified to adopt the following six additional guiding principles proposed in CalCCA's Comments on the Track 1 and Track 2 Ruling to inform the development of governance and oversight rules:[21]

- Nondiscriminatory market access, operations, and dispatch;
- Independent monitoring and oversight of the DSO and market functions;
- Optimization of existing distribution grid capacity before authorization of capital investments;
- Competitive neutrality of the DSO and marketplace operator;
- Fair compensation for flexibility services; and
- Timely access to accurate customer usage, DER, integration capacity analysis, and grid data.

Guiding principles provide alignment and focus to shape decision-making and serve as the foundation for the rules of governance and oversight, as well as the DER orchestration framework. The additional guiding principles proposed by CalCCA are squarely focused on addressing potential conflicts of interest, market power, and open access considerations.

The PD adopted eleven guiding principles to shape the development of the DER orchestration framework but declined to "adopt suggestions to modify and refine guiding principles in proceedings where IOU applications are being reviewed."[22] Since the PD failed to address governance and oversight before the submission of the Joint IOU Application, the Commission should adopt the additional guiding principles listed above.

B. Track 2 Should Be Extended for the Duration of a Working Group Series Led by Energy Division Rather Than the IOUs

Governance and oversight are foundational to developing an IOU-led DER orchestration framework and should be established within a formal proceeding to allow for the development of a more fulsome record before the submission of the Joint IOU Application. The Commission should extend Track 2 of this proceeding for the duration of the working group series to allow the working

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[21] *See CalCCA's Comments in Response to the Assigned Commissioner's Ruling on Track 1 and Track 2 DER Orchestration*, R.21-06-017 (Apr. 20, 2026), at 12, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M605/K328/605328509.PDF; and *Assigned Commissioner's Ruling on Track 1 and Track 2 Distributed Energy Resources Orchestration* (Track 1 and Track 2 Ruling), R.21-06-017 (Mar. 23, 2026), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M602/K997/602997407.PDF.

[22] Proposed Decision at 21.

group and the Commission to resolve the conflict of interest and market power concerns, and establish appropriate guardrails such as reporting requirements, data transparency protocols, and policies that enable ongoing stakeholder review. Once these rules have been established, the working group can begin vetting proposals for a common DER orchestration framework.

In addition, the Proposed Decision should be modified to require Energy Division, rather than the IOUs, to retain the consultant to lead the working group and prepare reports. The Commission, not the IOUs, should lead the process for developing the rules that will govern utility authority, competitive neutrality, and oversight of DER orchestration. Delegating this responsibility to the IOUs, whose conduct and decision-making will be subject to these rules, introduces bias into the process and undermines efforts to minimize grid investments and deliver ratepayer benefits.

The consultant will play a critical role in leading the working groups and preparing recommendations based on stakeholder input during those sessions. The consultant can shape the agenda, prioritize issues for deliberation, frame available alternatives, and influence which recommendations are included in the final reports. Allowing Energy Division to select and manage the consultant ensures balanced stakeholder participation and increases confidence in the process and resulting findings and recommendations.

C. The Working Group Series Should Begin with a Phase 1 Aimed at Resolving Concerns About Potential IOU Conflicts and Anti-Competitive Behavior

The proposed working group series should begin with a Phase 1 to address concerns about potential IOU conflicts of interest and anti-competitive behavior before establishing a common DER orchestration framework in Phase 2. The Commission should establish governance and oversight measures to protect against conflicts of interest, as well as rules and requirements for competitive neutrality, data access, cost allocation, and evaluation of demand-flexibility solutions relative to traditional grid investments. Without stakeholder discussion, the Commission should not prematurely determine that the IOU DSO requires dispatchable control over DERs participating in the DER orchestration framework,[23] nor establish subjective criteria for the participation of non-IOU DER aggregators.[24] The authority to establish a DER orchestration framework, under which non-IOU resources must be allowed to participate, should not be delegated to the IOUs until the Commission first establishes these rules and safeguards.

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[23] OIR at 36, Finding of Fact 9, Conclusion of Law (COL), Ordering Paragraph (OP) twenty-seven.

[24] OIR at 39, COL 25, OP 25.

As discussed in greater detail below, the Proposed Decision should be modified to require that: (1) the working group conduct an evaluation of lessons learned from other jurisdictions in which demand flexibility markets have been successfully deployed to inform governance and oversight of the DER orchestration framework; (2) a working group report with recommendations to address IOU conflicts of interest and market power concerns be submitted into the record to allow formal stakeholder comments; and (3) the Commission issue a decision resolving these issues before the working group begins vetting proposals for a common DER orchestration framework in Phase 2.

1. An Evaluation Should Be Performed of Lessons Learned From Jurisdictions That Have Successfully Deployed Demand Flexibility Markets

Phase 1 should include an evaluation of lessons learned from other jurisdictions that have successfully deployed demand flexibility markets, including the United Kingdom, to inform governance and oversight rules for a DER orchestration framework. The purpose of this evaluation is not to overlay another jurisdiction's model onto the proposed framework, but rather to identify implementation and regulatory challenges, regulatory safeguards, and ratepayer cost and benefit outcomes. Although demand flexibility markets are distinct from DER orchestration, their governance requirements offer valuable insights for developing rules tailored to California's regulatory structure and market conditions. Moreover, since the proposed DER orchestration framework may ultimately encompass the platforms, operational processes, data-sharing arrangements, and safeguards used in demand flexibility markets, evaluating this experience will help inform a California-centric approach.

An evaluation of successful demand flexibility markets is particularly relevant to California's established regulatory model, under which IOUs earn an authorized rate of return on capital assets included in the ratebase. DER orchestration and demand flexibility markets allow customer- and third-party-owned resources to provide services that could potentially reduce or eliminate grid infrastructure investments. An evidence-based evaluation of successful demand flexibility markets could help the Commission determine which governance functions remain with the IOUs, and which require oversight by an independent entity or by the Commission.

2. The Phase 1 WG Report Addressing Conflicts of Interest and Market Power Issues Should Be Submitted to the Record to Allow Formal Stakeholder Comments and a Commission Decision

The consultant, with input from Energy Division and the working group, should be directed to prepare a report with recommendations to address conflicts of interest and market power issues, to be submitted to the proceeding to allow formal stakeholder comments. The report should include the

results of the comparative evaluation of lessons learned from other jurisdictions and should accurately reflect stakeholder discussions, positions, and recommendations. After formal stakeholder comments, the Commission should issue a decision providing the governance and oversight needed to address conflicts of interest and prevent market power.

Once the final Phase 1 working group report and party comments have been submitted, the Commission should issue a decision establishing rules for governance and oversight before the working group begins vetting proposals for a common DER orchestration framework. This establishes the foundation upon which the orchestration framework will be built, minimizes the potential for conflicts of interest and anti-competitive practices, and maximizes potential ratepayer benefits. A formal decision that resolves conflicts of interest and anti-competitive practices builds confidence in the resulting DER orchestration framework, encouraging greater participation by customers and DER aggregators and amplifying potential benefits.

D. Phase 2 of the Working Group Should Begin After the Phase 1 Decision and Should Address the Common DER Orchestration Framework

After the final decision has been issued, the working group should be directed to continue deliberations, focusing on vetting proposals for a common DER orchestration framework. The final Phase 2 working group report should be submitted to the record, allowing parties to file formal comments, either at the conclusion of this proceeding or as part of the succeeding application proceeding.

IV. IF CALCCA'S TRACK 2 WORKING GROUP RECOMMENDATIONS ARE NOT ADOPTED, THE DECISION SHOULD AT A MINIMUM ACKNOWLEDGE THE EXISTENCE OF IOU CONFLICTS OF INTEREST AND ESTABLISH A VENUE TO ADDRESS THESE ISSUES

If the Commission fails to adopt the recommendations contained herein, the Proposed Decision should, at a minimum, acknowledge the potential conflicts of interest and market power concerns in the Findings of Fact and establish a venue to address these concerns in the Conclusions of Law. As noted in the Response, the Commission first identified these concerns in the OIR and then placed them at the center of Track 2 in the 2021 Scoping Memo.[25] The Amended Scoping Memo also recognized the market power issue but neglected to address these concerns.[26] Failure to acknowledge and address these important concerns could seriously undermine customer and DER-provider confidence in the

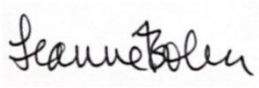
[25] Response, at 5.
[26] *Ibid.*

adopted orchestration framework, discouraging participation and diminishing potential ratepayer benefits from avoided grid investments.

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

October 19, 2026

APPENDIX A
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION ADOPTING AN APPLICATION PROCESS FOR UTILITY DISTRIBUTED ENERGY RESOURCES ORCHESTRATION AND ORDERING UTILITIES TO INCORPORATE LOAD FLEXIBILITY SCENARIOS INTO THEIR DISTRIBUTION PLANNING AND EXECUTION PROCESSES
PROPOSED CHANGES TO FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDERING PARAGRAPHS

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

FINDINGS OF FACT

1. Net ratepayer benefits, operational cost reductions, distribution capacity, reliability, and emissions reduction are primary objectives of DER orchestration and support the efficient and cost-effective integration of DERs into the electric grid. **Nondiscriminatory, fair, and open c**~~**C**~~ustomer and aggregation participation pathways may support achievement of these objectives.

4. Adopting the **following** DER orchestration guiding principles, **in addition to those** listed in the March 23 Ruling, as modified by this decision, ~~**together with the addition of "safe and reliable grid operation,"**~~ will help align the IOUs' Joint DER Orchestration Application with the overall goals of R.21-06-017**:**~~**.**~~

- **Safe and reliable grid operation;**
- **Nondiscriminatory market access, operations, and dispatch;**
- **Independent monitoring and oversight of the DSO and market functions;**
- **Optimization of existing distribution grid capacity before authorization of capital investments;**
- **Competitive neutrality of the DSO and marketplace operator;**
- **Fair compensation for flexibility services; and**
- **Timely access to accurate customer usage, DER, integration capacity analysis, and grid data.**

5. The existing Commission-led workshops and subsequent party comments sufficiently developed the record to establish **minimum** DER orchestration **pre-**application requirements **but did not sufficiently address conflict of interest or nondiscriminatory market access concerns**. **Additional stakeholder engagement, through a dedicated phase of the working group process, is needed to address these issues before vetting a common DER orchestration framework. Once governance and oversight issues have been resolved, additional p**~~**P**~~re-application stakeholder engagement, including through a working group, will provide important input to inform the IOUs' Joint DER Orchestration Application.

6. ~~**Topics covered by the pre-application working group led by an IOU-contracted facilitator would include the following:**~~

~~**(a) Guiding principles refinement;**~~
~~**(b) Valuation frameworks;**~~
~~**(c) Cost effectiveness and benefit-cost methodologies;**~~
~~**(d) Interoperability, DSO visibility, and dispatch and control;**~~
~~**(e) Role of DER aggregators;**~~
~~**(f) Flexible dispatching mechanisms;**~~
~~**(g) IOU technical readiness;**~~
~~**(h) Ownership of technology;**~~
~~**(i) Phased implementation and deployment;**~~
~~**(j) DER orchestration and real-time pricing.**~~

The pre-application working group, led be an Energy Division-contracted facilitator, would proceed in two phases. Phase 1 would address guiding principles, governance safeguards, data access, competitive neutrality, stakeholder participation, and minimum application requirements. Phase 2 would begin after a decision is issued resolving the Phase 1 issues listed above. Phase 2 would address the following topics:

a. Valuation frameworks;
b. Cost-effectiveness and benefit-cost methodologies;
c. Interoperability, DSO visibility, and dispatch and control;
d. Role of DER aggregators;
e. Flexible dispatching mechanisms;
f. TSO-DSO coordination;
g. IOU technical readiness;
h. Ownership of technology;
i. Phased implementation and deployment; and
j. DER orchestration and real-time pricing.

9. DSO-led DER orchestration requires DER visibility into the DSO ~~**and DER dispatchability and control**~~ as well as coordination with the CAISO during the application process.

10. DER aggregators may provide value by managing customer DERs and providing coordinated DER services, provided that their participation is subject to the same performance ~~**and accountability requirements as IOUs**~~**, measurement, verification, and accountability requirements appropriate to the services they provide and that do not create unnecessary barriers to competitive participation**.

17. A common DER orchestration framework approach ~~**will**~~ **can** provide efficiencies and better visibility of DER resources that will benefit customers**, provided the framework includes open and nondiscriminatory participation, competitive neutrality, decision-grade data access, transparent valuation and compensation, and Commission oversight sufficient to ensure that DER portfolios are fairly compared against traditional infrastructure alternatives**.

NEW FINDINGS OF FACT

X. Extending Track 2 of the proceeding allows for the creation of a robust record to address the unresolved conflict of interest and market power concerns identified in the OIR, and for the Commission to issue a decision establishing governance and oversight rules that will serve as the basis for the common DER orchestration framework.

X. Requiring Energy Division to retain a consultant to oversee the working group process and to prepare working group reports ensures fairness and reduces potential bias.

X. Orchestration of customer- and third-party-owned DER is separate and distinct from the IOUs' responsibility for operating and maintaining the distribution grid and requires rules for governance and oversight. A dedicated phase of the working group proceeding will allow formal stakeholder input to address concerns about potential IOU conflicts of interest and nondiscriminatory market access under an IOU-led DER orchestration framework. An evaluation of lessons learned from jurisdictions where demand flexibility markets have been successfully deployed will inform the development of governance and oversight rules applicable to California. A Phase 1 working group report, prepared by a consultant retained by Energy Division, will inform a Commission decision establishing governance and oversight, which will serve as the basis for development of the DER orchestration framework.

ALTERNATIVE FINDING OF FACT

5 The existing Commission-led workshops and subsequent party comments sufficiently developed the record to establish **minimum** DER orchestration **pre-**application requirements **but did not sufficiently address conflict of interest or nondiscriminatory market access concerns raised in the Order Instituting Rulemaking for R.21-06-017, and in subsequent Scoping Rulings. Governance and oversight issues must be addressed to resolve these concerns, ensure the DER orchestration framework's success, and maximize ratepayer benefits**. ~~**Pre-application stakeholder engagement, including through a working group, will provide important input to inform the IOUs' Joint DER Orchestration Application.**~~

CONCLUSIONS OF LAW

7. The IOU DER orchestration framework application should be guided by the following ~~**11**~~ **17** guiding principles:

- Net-Ratepayer benefits;
- Technology-neutral, performance-based;
- Locational and temporal value recognition;
- Efficient operation of the grid;
- Open access and Interoperability;
- Transparent participation pathways and compensation;
- Incremental, evidence-based implementation;
- Equity and customer protection;
- Cyber-secure and resilient;
- Preventing double compensation; ~~**and**~~

- Safe and reliable grid operation**;.**
- **Nondiscriminatory market access, operations, and dispatch;**
- **Independent monitoring and oversight of the DSO and market functions;**
- **Optimization of existing distribution grid capacity before authorization of capital investments;**
- **Competitive neutrality of the DSO and marketplace operator;**
- **Fair compensation for flexibility services; and**
- **Timely access to accurate customer usage, DER, integration capacity analysis, and grid data.**

8. **~~The IOUs~~ Energy Division** shall contract for a facilitator to jointly convene a working group meeting series, **to be funded by the IOUs**. **The working group meeting series should begin with a Phase 1 to address IOU conflicts of interest and market power concerns. The Phase 1 working group should include an evaluation of lessons learned from jurisdictions such as the United Kingdom, where demand flexibility markets have been successfully deployed. Energy Division should direct its consultant to prepare a Phase 1 report, including recommendations to address conflicts of interest and market power issues, which should be submitted to the proceeding to allow formal stakeholder comments. The Phase 1 report should include the results of the comparative evaluation of lessons learned from other jurisdictions and should accurately reflect stakeholder discussions, positions, and recommendations. The Commission should issue a decision adopting governance and oversight rules based on the Phase 1 report and formal party comments, to serve as the basis for developing a DER orchestration framework during the next phase of the working group.** The **Phase 1 working group** topics covered should include the following:

a. Guiding principles **~~refinement~~**;
b. Governance and oversight rules;
c. Competitive neutrality;
d. Nondiscriminatory market access;
e. Data access; and
f. Minimum DER orchestration application requirements.
b. **~~Valuation frameworks;~~**
~~c. Cost effectiveness and benefit-cost methodologies;~~
~~d. Interoperability, DSO visibility, and dispatch and control;~~
~~e. Role of DER aggregators;~~
~~f. Flexible dispatching mechanisms;~~
~~g. IOU technical readiness;~~
~~h. Ownership of technology;~~
~~i. Phased implementation and deployment;~~
~~j. DER orchestration and real-time pricing.~~

The Phase 2 working group should begin vetting proposals for a DER orchestration framework after the decision establishing governance and oversight rules is issued. Energy Division should direct the consultant to prepare a Phase 2 report with recommendations for a DER orchestration framework, which should be submitted to the proceeding to allow

formal stakeholder comments. The Phase 2 working group topics covered should include the following:

a. Valuation frameworks;
b. Cost-effectiveness and benefit-cost methodologies;
c. Interoperability, DSO visibility, and dispatch and control;
d. Role of DER aggregators;
e. Flexible dispatching mechanisms;
f. TSO-DSO coordination;
g. IOU technical readiness;
h. Ownership of technology;
i. Phased implementation and deployment; and
j. DER orchestration and real-time pricing.

9. The working group meeting series, including preparing **Phase 1 and Phase 2 reports, and the issuance of a decision adopting governance and oversight rules** ~~**a report to be included with the Joint IOU DER Orchestration Application**~~, should be completed within ~~**10**~~ **12** months from the issuance of this decision. ~~**The IOUs should allow parties**~~**Parties** to this proceeding **should be allowed** to provide ~~**in**~~formal comments on the draft report**s and a proposed decision adopting governance and oversight rules** within those ~~**10**~~ **12** months. The IOUs should then include the final **Phase 2** report as part of the joint application to be filed within ~~**12**~~**14** months of the issuance of this decision.

10. As part of the working group, or in addition, the IOUs should convene at least one pre-application stakeholder workshop before filing their applications. This meeting or meetings should occur after the issuance of the draft **Phase 2** working group report. Additional engagement should occur in consultation with Energy Division and should not delay the application filing deadline.

25. IOUs should consider in their joint application the role of DER aggregators in an orchestration framework and allow aggregators to provide coordinated DER services where their participation adds value~~**,**~~ **and** is cost-effective~~**, and does not introduce unnecessary complexity**~~. Participating aggregators should be subject to ~~**the same performance and accountability requirements as the IOUs**~~ **performance, measurement, verification, and accountability requirements appropriate to the grid services they provide, and those requirements should not create unnecessary barriers to competitive participation**.

27. The IOUs should describe the operational coordination necessary to enable communication with ~~**and dispatchable control over**~~ participating DERs to respond to DSO operational needs, identifying implementation differences across the IOUs where necessary.

28. The IOUs should identify in their joint application the roles of utilities, aggregators, CCAs, customers, and other DER providers and address safeguards for competitive neutrality and appropriate Commission oversight**, informed by stakeholder input in the Phase 1 and Phase 2 working groups**.

33. The IOUs should be permitted to submit optional Tier 2 advice letters within two months of adoption of this decision to establish memorandum accounts to record administrative costs to support the development of the DER orchestration application, including support for **the consultant retained by Energy Division to facilitate the** working group and any minor studies to support the application. Across the three IOUs, the total budget for these memorandum accounts should be capped at $500,000.

40. The IOUs should seek ~~in~~formal written feedback on their proposal, which should be included in their advice letter filing.

43. It is reasonable to deny all motions related to Track 1 and Track 2 of this proceeding ~~that were not ruled on~~**, except for the September 10, 2026, Center for Biological Diversity and Utility Consumers' Action Network Motion to Address Unaddressed Issues.**

NEW CONCLUSIONS OF LAW

X. Track 2 of the proceeding should be extended for the duration of the working group series to allow for the creation of a robust record to address the unresolved conflict of interest and market power concerns identified in the Order Instituting Rulemaking for R.21-06-017.

X The Commission should issue a decision establishing governance and oversight rules to serve as the basis for the common DER orchestration framework. The decision should be based on the consultant's Phase 1 working group report and formal party comments. The issuance of the decision should conclude the first phase of the working group series and should serve as the basis for vetting a common DER orchestration framework in the second phase of the working group.

ALTERNATIVE CONCLUSIONS OF LAW

X **The working group process should address the IOU conflicts of interest and market power concerns raised in the Order Instituting Rulemaking for R.21-06-017, and in subsequent Scoping Rulings. The consultant's working group report should include recommendations for governance and oversight rules to address these concerns, ensuring the success of the DER orchestration framework and maximizing ratepayer benefits**.

ORDERING PARAGRAPHS

1. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall submit a Joint Distributed Energy Resources Orchestration Application to the Commission within ~~12~~**14** months of the issuance of this decision.

2. ~~**Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company**~~**Energy Division** shall host a working group meeting series to address the topic areas **identified in** this decision**.** ~~**directs the utilities to include in a Joint Distributed Energy Resources Orchestration Application.**~~ **The working group meeting series shall begin with a Phase 1 to address IOU conflicts of interest and market power concerns. The Phase 1 working group shall include an evaluation of lessons learned from**

jurisdictions such as the United Kingdom, where demand flexibility markets have been successfully deployed. Energy Division shall direct its consultant to prepare a Phase 1 report, including recommendations to address conflicts of interest and market power issues, which shall be submitted to the proceeding to allow formal stakeholder comments. The Phase 1 report shall include the results of the comparative evaluation of lessons learned from other jurisdictions and shall accurately reflect stakeholder discussions, positions, and recommendations. The Commission shall issue a decision adopting governance and oversight rules based on the Phase 1 report and formal party comments, to serve as the basis for developing a DER orchestration framework in the next phase of the working group. The Phase 1 working group topics covered shall include the following: ~~**This includes the following:**~~

a. Guiding principles ~~**refinement**~~;
b. Governance and oversight rules;
c. Competitive neutrality;
d. Nondiscriminatory market access;
e. Data access; and
f. Minimum DER orchestration application requirements.

~~**a. Guiding principles refinement;**~~
~~**b. Valuation frameworks;**~~
~~**c. Cost effectiveness and benefit-cost methodologies;**~~
~~**d. Interoperability, DSO visibility, and dispatch and control;**~~
~~**e. Role of DER aggregators;**~~
~~**f. Flexible dispatching mechanisms;**~~
~~**g. IOU technical readiness;**~~
~~**h. Ownership of technology;**~~
~~**i. Phased implementation and deployment;**~~
~~**j. DER orchestration and real-time pricing.**~~

The Phase 2 working group shall begin vetting proposals for a DER orchestration framework after the decision establishing governance and oversight rules is issued. Energy Division shall direct the consultant to prepare a Phase 2 report with recommendations for a DER orchestration framework, which shall be submitted to the proceeding to allow formal stakeholder comments. The Phase 2 working group topics covered shall include the following:

a. Valuation frameworks;
b. Cost-effectiveness and benefit-cost methodologies;
c. Interoperability, DSO visibility, and dispatch and control;
d. Role of DER aggregators;
e. Flexible dispatching mechanisms;
f. TSO-DSO coordination;
g. IOU technical readiness;
h. Ownership of technology;
i. Phased implementation and deployment; and
j. DER orchestration and real-time pricing.

3. The working group and draft working group report shall be submitted to parties of this proceeding for informal comment within ~~10~~**12** months of the issuance of this decision. The final working group report, which will consider the comments on the informal report, shall be included as an attachment to the Joint Investor-Owned Utilities Distributed Energy Resources Orchestration Application.

8. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to follow ~~11~~**17** guiding principles as part of their distributed energy resources orchestration applications:

- Net Ratepayer benefits;
- Technology-neutral, performance-based;
- Locational and temporal value recognition;
- Efficient operation of the grid;
- Open access and interoperability;
- Transparent participation pathways and compensation;
- Incremental, evidence-based implementation;
- Equity and customer protection;
- Cyber-secure and resilient;
- Preventing double compensation; ~~**and**~~
- Safe and reliable grid operation~~.~~**;**
- **Nondiscriminatory market access, operations, and dispatch;**
- **Independent monitoring and oversight of the DSO and market functions;**
- **Optimization of existing distribution grid capacity before authorization of capital investments;**
- **Competitive neutrality of the DSO and marketplace operator;**
- **Fair compensation for flexibility services; and**
- **Timely access to accurate customer usage, DER, integration capacity analysis, and grid data.**

25. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to address in their Joint Distributed Energy Resources (DER) Orchestration Application the potential role of DER aggregators**, CCAs, customers, and other DER providers** in their proposed orchestration frameworks. ~~**If aggregators are included they must add value, not undermine the goal of cost effectiveness, nor add unnecessary complexity**~~.**The application shall allow qualified aggregators, CCAs, customers, and other DER providers to provide coordinated DER services where their participation adds value and is cost-effective. Participation requirements shall be based on the grid service provided and shall not create unnecessary barriers to competitive participation.**

27. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to explain in their Joint Distributed Energy Resources (DER) Orchestration Application how their proposed flexible dispatching mechanisms can schedule and dispatch DER flexibility based on identified distribution system needs and how they will ~~**exercise communication and dispatch control over**~~ **communicate with** participating DERs, including the mechanisms necessary to ensure DERs respond to distribution system operator operational needs.

41. All motions related to Track 1 and Track 2 of this proceeding that were not ruled on are denied**, except for the September 10, 2026, Center for Biological Diversity and Utility Consumers' Action Network Motion to Address Unaddressed Issues.**

NEW ORDERING PARAGRAPHS

X. Track 2 of the proceeding shall be extended for the duration of the working group series to allow for the creation of a robust record to address the unresolved conflict of interest and market power concerns identified in the Order Instituting Rulemaking for R.21-06-017.

X The Commission shall issue a decision establishing governance and oversight rules to serve as the basis for the common DER orchestration framework. The decision shall be based on the consultant's Phase 1 working group report and formal party comments. The issuance of the decision shall conclude the first phase of the working group series and shall serve as the basis for vetting a common DER orchestration framework in the second phase of the working group.

ALTERNATIVE ORDERING PARAGRAPHS

X The working group process shall address the IOU conflicts of interest and market power concerns raised in the Order Instituting Rulemaking for R.21-06-017, and in subsequent Scoping Rulings. The consultant's working group report shall include recommendations for governance and oversight rules to address these concerns, ensuring the success of the DER orchestration framework and maximizing ratepayer benefits.

1. **Please provide your organization's comments on the Large Loads Enhancements draft tariff language in tracked changes.**

   Please find attached the BAMx redlines to the Large Loads Enhancements draft tariff language.

AltaGas
Bay Area Municipal Trans…
California Community Choic…
California Department of Wa…
California Large Energy Con…
Constellation
Founder | Persistence Analyt…
LS Power
ModsSys LLC
Northern California Power A…
Pacific Gas and Electric Co…
Power Applications and Res…
Southern California Edison
SunZia Transmission LLC
Voltus, Inc.

Bay Area Municipal Transmission Group (BAMx)

SUBMITTED 10/15/2026, 04:12 PM

Submitted on behalf of

City of Santa Clara dba Silicon Valley Power and City of Palo Alto Utilities

California Community Choice Association

SUBMITTED 10/15/2026, 02:56 PM

Contact

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

1. **Please provide your organization's comments on the Large Loads Enhancements draft tariff language in tracked changes.**

   The California Community Choice Association (CalCCA) appreciates the opportunity to comment on the Large Loads Enhancements draft tariff language. CalCCA's recommended redlines acknowledge that there is the need to identify additional data related to large load operations, but provide the CAISO's proposed implementation working group the opportunity to further develop these requirements with sufficient input from required stakeholders. CalCCA's comments on the Draft Final Proposal identify the reasons why additional time and process is required before adopting comprehensive requirements for data reporting from the SC to the CAISO.

   25.7.3 ~~Load Serving Entity Scheduling Coordinator Requirements~~ Large Load Operational Requirements

   Day-ahead forecasts, hourly forecasts, operational status, real-time consumption in accordance with the CAISO's standards for direct telemetry and consistent with the requirement for telemetry set forth in Section 7.6.1, and other operational data the CAISO requires to maintain sufficient operational visibility must be provided to the CAISO for each Large Load. The entity responsible for providing each category of data, the applicable data exchange requirements and communication protocols, and any additional data requirements will be as specified in the applicable Business Practice Manual.

   ~~The SC representing the Load Serving Entity's service area for the Large Load will include the Large Load in its Bids, Scheduled Demand, and Meter Data, as applicable, for that area. The Scheduling Coordinator also must provide the CAISO the following, specific to each Large Load it represents:~~

   1. ~~Daily and hourly forecast data otherwise required for the CAISO Forecast of CAISO Demand;~~
   2. ~~Any real-time, material change from provided forecasts, including changes resulting from energization activities, material operational changes, curtailments, Outages, derates, operating limits, operating envelopes, or co-located generation impacts that materially affect expected Demand;~~
   3. ~~Planned Outages, forced Outages, derates, and other operating conditions that materially affect the Large Load's expected consumption or operating capability; and~~
   4. ~~Operational status and real-time consumption to the CAISO in accordance with the CAISO's standards for direct telemetry and consistent with the requirement for telemetry set forth in Section 7.6.1~~

   25.7.3.1 Load Serving Entity Scheduling Coordinator Requirements

   The Scheduling Coordinator representing the Load Serving Entity's service area for the Large Load will include the Large Load in its Bids, Scheduled Demand, and Meter Data, as applicable, for that area.

   25.7.3.~~1~~ 2 Large Load Scheduling Coordinator Requirements

   If permitted by the Local Regulatory Authority to be its own Load Serving Entity, a Non-Generator Resource, or a Participating Load, the Large Load may elect to comply with the requirements of Section

25.7.3 and participate in the CAISO Markets through its own Scheduling Coordinator in lieu of the service area Load Serving Entity Scheduling Coordinator. A Large Load participating as a Proxy Demand Resource or Reliability Demand Response Resource will have the service area Load Serving Entity Scheduling Coordinator comply with Section 25.7.3 and submit Scheduled Demand including the Large Load, but may have the Demand Response Provider or other Scheduling Coordinator comply with Section 4.13.

California Department of Water Resources - State Water Project

SUBMITTED 10/16/2026, 02:48 PM

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1. **Please provide your organization's comments on the Large Loads Enhancements draft tariff language in tracked changes.**

CDWR-SWP opposes CAISO's definition of Large Load because it does not specify that the definition applies only to new large load interconnections. CDWR-SWP asks CAISO to adopt the following definition instead:

> **Large Load – A new** End User located at a single site whose Point of Interconnection is to the CAISO Controlled Grid, and that has a peak load of 50 MW or greater.

Adopting this revised definition would be consistent with the potential definition suggested by FERC's Show Cause Order (at P 1 n.2) which limits the definition to "a new commercial or industrial customer…" and FERC's stated intention not "to disrupt existing commercial arrangements, but rather to establish prospective reforms." Order at P 5. It is also consistent with CAISO's statements in the Draft Final Proposal. See, e.g. Proposal at 3 ("CAISO offers this proposal to establish new procedures for fast and reliable interconnection of new large loads.").

Without this change, the proposed definition of Large Loads would appear to encompass existing End Users with significant loads located at a single site, including potentially CDWR-SWP. That would subject such existing End Users to significant new tariff obligations (such as those included in new tariff section 25.7.3) without any change to their existing operations and without any stakeholder review of the need for or feasibility of imposing those new tariff obligations on existing End Users. CDWR-SWP does not believe that this is CAISO's intended outcome based on the Draft Final Proposal and CAISO's previous comments that the Large Load definition only applies to new interconnections. If CAISO believes the proposed Large Load definition and tariff revisions cannot be read to apply to existing End Users, CDWR-SWP requests that CAISO explain in detail why that is the case.

CDWR-SWP again requests clarification of whether large loads are retail or wholesale customers. In particular, Footnote 34 says a Participating Load Agreement isn't required because it applies only to loads receiving wholesale service, "which are not relevant to this initiative at this time." CDWR-SWP requested this clarification in its September 2 Comments, but CAISO did not provide any clarification. Instead, CAISO introduced additional uncertainty by including Draft Tariff Language that allows Large Loads to "participate in the CAISO Markets using any model where they are capable of complying with the CAISO Tariff requirements, including without limitation as…Participating Loads."

California Large Energy Consumers Association

SUBMITTED 10/15/2026, 01:56 PM

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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 2027 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U 39 E).	A. 26-05-007

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING BRIEF

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October 21, 2026

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SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Contested Issues

- The Commission[1] should order PG&E to modify its methodology for calculating the Retained RA from non-storage resources and align that methodology with SCE's interim methodology and the Commission's Slice-of-Day framework for RA compliance.

- The Commission should permit PG&E to apply Unsold RPS volumes towards its Minimum Retained RPS requirement. However, the Commission should expressly limit PG&E's ability to displace the RECs it previously applied towards a prior year's Minimum Retained RPS requirement, and permit PG&E to make changes to its 2025 Minimum Retained RPS entry only to the extent it displaces previously-used banked RECs with expiring Unsold RPS volumes.

- The Commission should revisit the structure of the CCA meet-and-confer process in order to improve the accuracy of load forecasts used for ratemaking purposes. The Commission should undertake this effort in the ongoing PCIA OIR. The current meet-and-confer process, established in 2016, is not designed to account for rapid and uncertain load growth.

Uncontested Issues

- CalCCA supports PG&E's update to its RA valuation methodology for energy-storage resources to conform with the directives in D.26-07-008. However, PG&E should also align its RA valuation methodology for energy-only and long-duration energy storage resources with the same Decision.

- The Commission should permit PG&E to include the electric generation portion of the authorized interim revenue requirement from its 2027 GRC in 2027 rates.

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

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 2027 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U 39 E).	A. 26-05-007

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING BRIEF

Pursuant to Rule 13.11 of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission) and the schedule adopted in the Assigned Commissioner's Scoping Memo and Ruling (Scoping Memo),[2] the California Community Choice Association[3] (CalCCA) hereby submits this Opening Brief regarding the *Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements And Rates Associated with its 2027*

[2] Application (A.) 26-05-007, *Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2027 Energy Resource Recovery Account (ERRA) Generation Non-Bypassable Charges Forecast, and Greenhouse Gas Forecast Revenue Return and Reconciliation, Assigned Commissioner's Scoping Memo and Ruling* at 5 (Aug. 3, 2026) (Scoping Memo).

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

Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U 39 E) (Application).[4]

Pacific Gas and Electric Company's (PG&E) annual ERRA Forecast proceeding sets Power Charge Indifference Adjustment (PCIA) rates for the upcoming year. The PCIA is the mechanism the Commission uses to ensure "indifference" between bundled and departed customers, as required by California law. To achieve that objective, PCIA rates are set at levels that ensure departed customers remain responsible for the costs of PCIA resources previously incurred on their behalf—but only those costs that remain after the Commission accounts for benefits PCIA resources continue to impart to bundled customers. In this manner, the PCIA framework ensures both bundled and unbundled customers benefit from the resources for which they pay. For bundled customers, PG&E uses those resources to serve load and meet compliance obligations. For departed customers, PG&E credits the value of those resources' attributes against the costs departed customers owe to bundled customers. Striking this fine balance is important not only because the law mandates indifference, but also because PCIA rates can form a significant portion of the generation charges that customers pay.

In this ERRA Forecast proceeding, CalCCA examined several issues that impact the PCIA rates customers pay, including the Resource Adequacy (RA) value of PG&E's PCIA resource portfolio; the Renewables Portfolio Standard (RPS) value of that portfolio; and PG&E's sales and peak demand forecasts. This brief discusses several of those issues but focuses on the primary

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

remaining contested issue between PG&E and CalCCA: PG&E's calculation of the Retained RA value of its non-storage PCIA resources.

In last year's ERRA Forecast proceeding, the Commission adopted changes to PG&E's methodology for calculating the RA value of its storage resources. Those changes were motivated by the Commission's transition to a "Slice-of-Day" (SoD) framework for RA compliance,[5] under which load-serving entities (LSEs) must show sufficient capacity to meet 24 separate hourly RA requirements across each month of the year. The Commission directed PG&E to apply Southern California Edison Company's (SCE) interim SoD methodology to storage resources on an interim basis, recognizing that the Commission would eventually issue a "more comprehensive decision on implementation of the SoD methodology."[6] The Commission did not address the valuation of non-storage resources.

PG&E has now implemented SCE's interim SoD methodology for its storage resources, but its valuation of non-storage resources remains out of step with SCE (and with the Commission's transition to a SoD framework for RA compliance). Meanwhile, the Commission has yet to consider or develop a comprehensive set of reforms to the PCIA ratemaking framework to reflect SoD implementation. The Commission should therefore direct PG&E to align with SCE and apply SCE's interim SoD methodology to all resource types, not just to energy storage. This will help ensure PG&E's RA valuation methodology reflects RA resources' actual value under the SoD RA compliance framework.

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[5] Decision (D.) 25-12-027 at 37 (stating: "[w]e agree the Commission's RA regulatory program has changed enough to warrant a response in this expedited proceeding.")

[6] *Id*. at 37-38.

The remaining contested issues in this proceeding involve PG&E's RPS accounting and its data center load forecasting process. With respect to PG&E's RPS accounting, CalCCA supports PG&E's rebuttal proposal to apply Unsold RPS volumes towards its "Minimum Retained RPS requirement", because this would avoid those Unsold volumes expiring. However, one aspect of PG&E's proposal is to displace the RECs it was previously authorized to apply towards its 2025 Minimum Retained RPS requirement. Parties have already examined and litigated PG&E's 2025 Minimum Retained RPS requirement in multiple cases. The Commission should expressly limit PG&E's ability to displace the RECs it previously applied towards a prior year's Minimum Retained RPS requirement, and permit PG&E to make changes for 2025 only to the extent it displaces previously-used banked RECs with expiring Unsold RPS volumes.

With respect to PG&E's data center load forecast, CalCCA presented testimony illustrating the volatility that inaccurate load forecasts can create in the PCIA and observing that the sales forecast meet-and-confer process between PG&E and CCAs was established in an era before rapid load growth. To ensure data center load forecasts are as accurate as possible, and to mitigate PCIA rate volatility, the Commission should revisit the meet-and-confer process in the pending PCIA rulemaking.

Finally, this brief addresses three uncontested issues. First, PG&E has proposed a narrow change to its RA valuation methodology for storage resources to account for a recent Commission directive in the RA rulemaking related to "battery foldback" (D.26-07-008). CalCCA does not object to that change, but PG&E and CalCCA agree that PG&E should implement *all* directives in D.26-07-008, not just the directive related to battery foldback. Second, PG&E and CalCCA agree that PG&E should incorporate into 2027 rates the electric generation portion of any interim revenue requirement the Commission authorizes in PG&E's 2027 General Rate Case (GRC).

Third, PG&E has addressed the PCIA calculation errors CalCCA identified during the discovery process.

I. LEGAL STANDARDS

In light of the significant impact PG&E's Application will have on both departed and bundled customers, the ratemaking proposals in that Application require the Commission's careful consideration under the applicable legal standards. Those legal standards include requirements established by the Public Utilities Code. They also include the requirements established in prior Commission decisions, rules, regulations, and resolutions that create and subsequently modify the regulatory framework for the utilities' annual ERRA Forecast filings.

First, pursuant to Public Utilities Code Section 451:

> All charges demanded or received by any public utility, or by any two or more public utilities, for any product or commodity furnished or to be furnished or any service rendered or to be rendered shall be just and reasonable. Every unjust or unreasonable charge demanded or received for such product or commodity or service is unlawful.[7]

This foundational "just and reasonable" statutory requirement is applicable to all rates and charges, including those that will be established by this ERRA Forecast proceeding. Commission precedent supports cost-causation principles in setting "just and reasonable" rates, whereby customers are responsible for the costs incurred on their behalf.[8] The Public Utilities Code also requires rates to

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[7] Cal. Pub. Util. Code § 451.

[8] D.15-07-001 at 2 (Jul. 13, 2015) (citing *K N Energy, Inc. v. F.E.R.C.*, 968 F.2d 1295, 1300 (D.C. Cir. 1992) ("[I]t has been traditionally required that all approved rates reflect to some degree the costs actually caused by the customer who must pay them."); *Alabama Elec. Co-op., Inc. v. F.E.R.C.*, 684 F.2d 20, 27 (D.C. Cir. 1982) ('[I]t has come to be well established that electrical rates should be based on the costs of providing service to the utility's customers, plus a just and fair return on equity."); *So. Cal. Edison Authorized to Increase Rates for California Intrastate Electric Services*, 75 CPUC 641 (1973) (recognizing the desirability of each group's bearing its fair share of the cost of service, as such share is measured by the cost of service study).

be non-discriminatory. Public utilities are prohibited from establishing "any unreasonable difference as to rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service."[9]

ERRA Forecast proceedings also implicate statutory prohibitions on cost shifts between groups of bundled and unbundled customers, as PG&E emphasizes in its Application.[10] Section 365.2 of the California Public Utilities Code mandates indifference for departed customers, requiring the Commission to "ensure that departing load does not experience any cost increases as a result of an allocation of costs that were not incurred on behalf of the departing load."[11] Under Section 366.2, unbundled customers are responsible solely for "estimated net unavoidable electricity costs" when determining indifference, and those costs must be reduced by the benefits in the IOUs' portfolios that accrue to bundled customers.[12] The Commission effectuates that indifference mandate through PCIA rates, the 2027 levels of which are the focus of this brief.

II. BURDEN OF PROOF

As the ratemaking applicant, PG&E has the burden of proof on all aspects of its Application and must affirmatively establish the justness and reasonableness of each proposal therein.[13] That burden of proof includes a burden of production, which rests with PG&E on all facts material to its Application. The burden of production requires PG&E to present evidence sufficient to establish disputed facts in its favor by a requisite degree of belief, which in ERRA Forecast

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9 Cal. Pub. Util. Code § 453(c).

10 Application at 8-9.

11 Cal. Pub. Util. Code § 365.2.

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

13 D.23-08-027, *Decision Approving Partial Settlement*, A.21-09-008 (Aug. 18, 2023), at 16.

proceedings is a "preponderance of the evidence."[14] The burden of proof also includes a burden of persuasion, which remains with PG&E throughout this proceeding.[15] That means the Commission should not grant the relief PG&E requests unless a preponderance of the record evidence demonstrates PG&E has affirmatively satisfied its burden of proof with respect to that request.

III. STANDARD OF REVIEW

The Commission has previously determined that Section 1757 of the Public Utilities Code applies to ratesetting proceedings[16] such as the instant Application,[17] which means the final decision must be "supported by the findings," and those findings must be "supported by substantial evidence in light of the whole record" to withstand appeal. Therefore, the Commission should not grant the relief in PG&E's Application without substantial evidence to support the rates requested.[18] California courts will overturn Commission decisions that are not supported by substantial evidence.[19] Mere rubber-stamping of uncorroborated, disputed evidence does not meet this standard.[20] The Commission, therefore, must reject the components of PG&E's Application that are not supported by substantial evidence.

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[14] *See, e.g.*, D.18-01-009, A.17-06-005 (Jan. 16, 2018), at 9-10; D.15-07-044, R.11-02-019 (Jul. 27, 2015), at 29 (observing that the Commission has discretion to apply either the preponderance of evidence or clear and convincing standard in a ratesetting proceeding, but noting that the preponderance of evidence is the "default standard to be used unless a more stringent burden is specified by statute or the Courts.")

[15] *Cal. Farm Bureau Fed. V. State Water Resources Control Bd.*, 51 Cal. 4th 421, 436 (2011).

[16] Cal. Pub. Util. Code § 1757; *see, e.g.* D.20-05-027 at 5 (May 8, 2020) ("As an initial matter, SDG&E cites to the wrong statute, because Public Utilities Code section 1757.1 does not set forth the applicable standards for a ratesetting proceeding like this one. Rather, section 1757 provides the appropriate standard and requires a finding as to whether the Commission's findings are not supported by substantial evidence in light of the whole record.").

[17] Scoping Memo at 7.

[18] Cal. Pub. Util. Code § 1757(a)(4). *See, e.g. The Utility Reform Network v. Pub. Util. Comm'n*, 223 Cal. App. 4th 945, 958-59 (Feb. 5, 2014).

[19] *Id*.

[20] *Id*.

IV. BACKGROUND

A. BACKGROUND ON THE PCIA

Community choice aggregator (CCA) customers receive generation services from their local CCA, and receive transmission, distribution, billing, and other services from the incumbent for-profit utility. CCA customers pay CCA-specific generation rates. CCA rates vary and are partially influenced by local mandates to procure and maintain clean electricity portfolios that, in many cases, exceed state requirements for renewable generation. In addition, CCA and other unbundled customers are subject to several non-bypassable charges (NBC), including the PCIA and the Cost Allocation Mechanism (CAM) surcharge, the 2027 levels of which will be determined in this proceeding.

The Commission has an obligation to ensure "indifference," meaning when customers of investor-owned utilities (IOUs) depart from bundled service and receive their electricity from a non-IOU provider, such as a CCA, "those customers remain responsible for costs previously incurred on their behalf by the IOUs."[21] The PCIA is the tool the Commission adopted "intend[ing] to equalize cost sharing" between these two groups of customers.[22]

B. CALCULATION OF THE PCIA REVENUE REQUIREMENT

The PCIA revenue requirement is derived from two sources in each utility's ERRA Forecast case, as demonstrated in Figure 1.[23] The first is the Indifference Amount forecasted for the year *for which* rates are being set, *i.e.*, the Indifference Amount forecasted for 2027 in the

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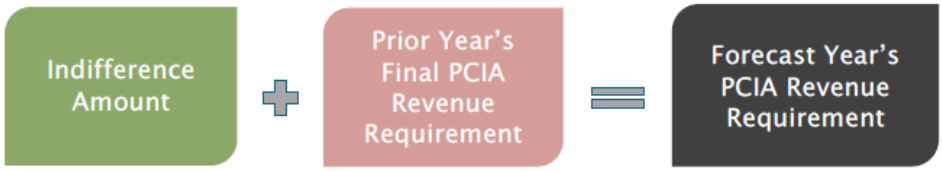
[21] D.24-12-038, *Decision Approving Pacific Gas and Electric Company's 2025 Energy Resource Recovery Account Related Forecast Revenue Requirement and 2025 Electric Sales Forecast*, A.24-05-009 (Dec. 20, 2024).

[22] *See* D.18-10-019 at 3.

[23] Exh. CalCCA-01C at 5.

instant proceeding.[24] The second is the final PCIA revenue requirement for the year *in which* rates are being set, *i.e.*, the final 2026 PCIA revenue requirement in the instant proceeding, which is derived from the balance in the Portfolio Allocation Balancing Account (PABA) the utility anticipates seeing at the end of the year.[25]

FIGURE 1



The Indifference Amount is the difference between the forecasted cost of the IOU's supply portfolio and the forecasted market value of the IOU's supply portfolio as demonstrated in Figure 2 below.[26]

FIGURE 2



Total Utility Portfolio Cost includes:

(i) the cost for Utility-Owned Generation (UOG) (*i.e.*, the capital investment recovery and fixed maintenance costs the Commission sets in a GRC);

(ii) purchased power such as that from power purchase agreements (PPAs);

(iii) fuel costs for UOG and PPAs with tolling agreements, and;

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24 *Id.*

25 *Id.*

26 *Id.*

(iv) California Independent System Operator (CAISO) grid charges and revenues, net of any sales.[27]

The forecasted Portfolio Market Value is derived from total eligible resource output multiplied by the Market Price Benchmarks (MPBs), an administratively determined set of proxy values that estimate the market value of the IOU's resource portfolio.[28] Portfolio Market Value consists of three principal components: Energy Value, RPS Value, and RA Value.

- Energy Value is the estimated financial value, measured in dollars, that is attributed to the generation component of a utility portfolio for a given year.[29]
- RPS Value is the estimated financial value, measured in dollars, that is attributed to the renewable energy component of a utility portfolio for a given year above and beyond the Energy Value.[30]
- RA Value is the estimated financial value, measured in dollars, that is attributed to the resource adequacy component of a utility portfolio for a given year.[31]

MPBs are estimates of the value per unit (not total portfolio value) associated with the three principal sources of value in utility portfolios (non-RPS energy, RPS, and RA capacity).[32] Each

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27 D.11-12-018, *Decision Adopting Direct Access Reforms*, R.07-05-025 (Dec. 1, 2011), at 8-9.

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

29 *Id.*

30 *Id.*

31 *Id.*

32 *Id*.

MPB must be multiplied by the relevant portfolio volume as part of the overall calculation of Portfolio Market Value:[33]

- Energy Index is the MPB that reflects the estimated market value of each unit of energy in a utility portfolio, in dollar value per megawatt hour ($/MWh). It is sometimes referred to as "Brown Power Index," "Brown Power component," "Brown Power Adder," or "Brown Power benchmark."[34]
- RPS Adder is the MPB that reflects the estimated incremental value of each unit of RPS-eligible energy in $/MWh.[35]
- RA Adder is the MPB that reflects the estimated value of each unit of capacity in a utility portfolio that can be used to satisfy Resource Adequacy obligations, in dollar value per kilowatt ($/kW-month).

The forecast utility portfolio value calculation is shown in Figure 3 below. [36]

FIGURE 3



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33 *Id.*

34 *Id.* at 7.

35 *Id.*

36 Exh. CalCCA-01C at 7.

The forward-looking, forecasted ingredients of total portfolio cost and value are netted against Utility Portfolio Costs to produce the Indifference Amount portion of the PCIA revenue requirement.[37]

The second portion of the PCIA revenue requirement is the "true up." The "true up" modifies the forecasted PCIA revenue requirement from the prior year to reflect, among other things, actual revenues received for products sold from the portfolio and to reflect a zero-dollar value for products left unsold from the portfolio.[38] The revenue requirement modification also updates the proxy market values for products the utilities used to serve bundled customers, changing the *forecast* energy, RPS, and RA MPBs to *final* energy, RPS, and RA MPBs.[39] This "true up" relies on the same methodology used for the forecast and determines the final portfolio value, as shown in Figure 4 below:[40]

FIGURE 4



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37 *Id*.

38 *Id*. at 8.

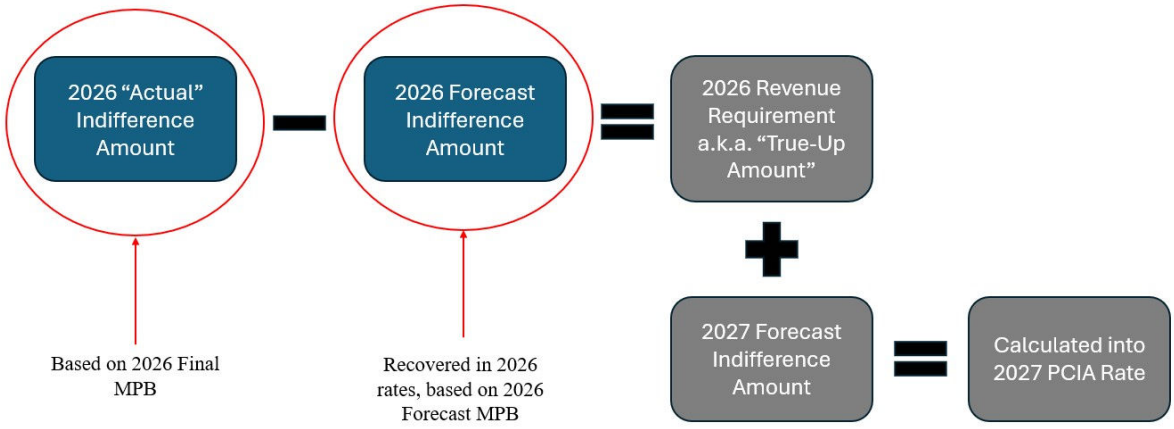
39 *Id*.

40 Because the true-up for 2026 occurs during 2026, this true-up is developed using (1) actual values that are available to date and (2) a forecast of actual values for the remainder of the year. PG&E's Application includes an estimate of the 2026 year-end PABA balance comprising a combination of actual entries from January through March 2026 and a projection of activity from April through December 2026. PG&E's October Update includes an estimate of the 2026 year-end PABA balance comprising a combination of actual entries from January through August 2026 and a projection of activity from September through December 2026. The final December 31, 2026, advice letter implementing the proceeding will include actual entries. *See id*. at 7, fn. 13.

Prior to D.18-10-019, the PCIA rate was set only on a forecast basis with no after-the-fact adjustment to the forecasted PCIA revenue requirement for unbundled customers.[41] Decision 18-10-019 approved such an adjustment via the PABA, a rolling balancing account tracking the difference between costs and revenues used to determine the forecasted PCIA revenue requirement and the actual costs and revenues PG&E realizes during the year related to its PCIA-eligible resource portfolio.[42]

PG&E calculates this final 2026 portfolio value, uses it as an input to the actual 2026 indifference amount, and finalizes the 2026 revenue requirement in this case, as shown below in Figure 5.[43]

FIGURE 5



To summarize, PG&E's PCIA rates for 2027 will be set in this proceeding based on these two components: (1) the forecasted Indifference Amount, *i.e.*, the difference between the forecasted cost of PG&E's generation portfolio in 2027 and the forecasted market value of PG&E's generation portfolio in 2026; and (2) the final 2026 PCIA revenue requirement based on the year-end balance

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41 *Id.* at 8.

42 *Id.*

43 *Id.* at 9.

in the PABA.[44] The Indifference Amount and the final 2026 PCIA revenue requirement are added together to form the 2027 PCIA revenue requirement recovered through rates from bundled and unbundled customers.[45] Finally, per D.22-01-023, the year-end ERRA Balance is transferred to the most recent PABA vintage, and is paid by both bundled and departing load customers that depart on or after July 1 of the preceding year.[46]

C. CUSTOMER VINTAGING AND ALLOCATION

Each generation resource and customer is assigned a "vintage."[47] A distinct portfolio of generation resources is identified for each vintage year based on when a commitment to procure each resource was made.[48] Customers are assigned to vintage years according to the date the customer departed bundled IOU service.[49] Customers continuing to receive bundled service from the IOU are included in the latest vintage (e.g., vintage 2027 in the current application).[50] Each vintage is assigned both a separate Indifference Amount and a separate final 2026 revenue requirement[51] and customers are responsible for the cumulative Indifference Amount for years prior to and including their vintage.[52] The PCIA revenue requirement is allocated among both

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44 *Id*.

45 *Id*.

46 D.22-01-023 at Ordering Paragraph (OP) 4.

47 Exh. CalCCA-01C at 9.

48 *Id*.

49 Unlike portfolio resources, customers are assigned to vintages using a July to June calendar period. For example, customers departing bundled service between July 2019 and June 2020 are assigned to the 2019 vintage. *See id*. at 10, fn. 16.

50 *Id*. at 10.

51 D.11-12-018 at 9.

52 Exh. CalCCA-01C at 10.

bundled and unbundled customers based on their vintage and their rate class using the allocation factors from PG&E's most recently approved GRC.[53]

V. CONTESTED ISSUES

A. THE COMMISSION SHOULD DIRECT PG&E TO ADOPT SCE'S INTERIM METHODOLOGY FOR ALL RESOURCE TYPES BECAUSE SCE'S METHODOLOGY REFLECTS THE COMMISSION'S TRANSITION TO A SLICE-OF-DAY FRAMEWORK

1. The Methodology Used To Determine RA Quantity Directly Impacts PCIA Rates.

As discussed above, a key component in PG&E's calculation of the value of its PCIA-eligible resources—which in turn drives the Indifference Amount recovered from bundled and unbundled customers through the PCIA—is the RA value of those resources.[54] PG&E calculates the RA value of its PCIA-eligible portfolio by multiplying the total RA quantity associated with that portfolio (in megawatts (MW)) by the RA MPB (in $ per kilowatt (kW)-month).[55] The RA MPB is an administratively-set proxy value provided each October by Energy Division and cannot be modified in this proceeding. The quantity term used to calculate the RA value of PG&E's portfolio, however, is a contested issue in this proceeding.

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53 D.18-10-019 at 122 and OP 4; Exh. CalCCA-01C at 10.

54 Exh. CalCCA-01C at 10.

55 *Id*.

2. The Commission Has Approved Changes to the IOUs' Methodologies for Determining RA Quantity In Order to Reflect the RA Program's Transition to the SoD Framework.

In recent years, the Commission's transition to a SoD framework[56] for RA compliance has impacted the quantity term used to calculate the RA value of the IOUs' PCIA portfolios in ERRA Forecast cases.

The SoD framework requires LSEs to show sufficient capacity to meet 24 separate hourly RA requirements across each month of the year.[57] From the perspective of an RA resource, the SoD framework considers the capacity contribution of that resource during each hour of the "worst day" of each month.[58] Prior to the Commission's implementation of the SoD framework, the Commission required LSEs to demonstrate compliance with RA program requirements based on the Net Qualifying Capacity (NQC) associated with their RA resources—a measure of each resource's capacity contribution in the single peak hour of each month.[59] The SoD framework is a marked transition away from the previous, NQC-centric approach to RA compliance.

The Commission has not issued any decision or guidance requiring LSEs to reflect the SoD RA compliance framework in PCIA ratemaking. Nevertheless, in recent ERRA cases, the IOUs have proposed certain changes to RA valuation for PCIA purposes to reflect the RA program's transition away from NQC-based compliance. In approving changes to the IOUs' RA valuation methodologies, the Commission has expressly characterized those changes as "interim" solutions,

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[56] The Commission adopted the "Slice-of-Day" framework through the 2021 RA program rulemaking, D.22-06-050 at 120-122, Findings of Fact 10-21, and it became effective in 2025. D.23-04-010, *Decision on Phase 2 of the Resource Adequacy Reform Track*, R.21-10-002 (Apr. 6, 2023), at 73.

[57] Exh. CalCCA-01C at 11.

[58] *Id*.

[59] *Id*.

and acknowledged the Commission intends to comprehensively address the impacts of the SoD framework on PCIA ratemaking in a rulemaking.

SCE was the first IOU to propose changes to its RA valuation methodology for PCIA ratemaking purposes to reflect the SoD framework. In its 2025 ERRA Forecast Case, A.24-05-007, SCE proposed an "interim slice of day methodology" that would "align the RA quantity calculation to account for CPUC-adopted changes in how RA resources are counted for compliance purposes."[60] Specifically, SCE's interim SoD methodology would determine RA capacity based upon the NQC of baseload resources,[61] the average of all 24 hours of SoD capacity for intermittent resources, and for storage resources—NQC minus an estimate of the RA capacity needed for charging.[62] CalCCA contested SCE's methodology for failing to comprehensively address the impact of SoD on RA quantity *and* price, among other things.[63] The Commission, however, found SCE's interim SoD methodology to be a "reasonable execution of guidance given to account for how [RA] is counted for compliance purposes" and approved SCE's application of that methodology on an interim basis.[64] The Commission again approved SCE's interim SoD methodology in SCE's 2026 ERRA Forecast proceeding, A.25-05-008, reiterating its finding from

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60 D.24-12-039, *Decision Approving Southern California Edison Company's 2025 Energy Resource Recovery Account-Related Forecast Revenue* Requirement, A.24-05-007 (Dec. 23, 2024), at 70.

61 The RA value of baseload resources does not change under a SoD framework because those resources contribute the same or near the same RA value (NQC) across all 24 hours of the day.

62 Exh. CalCCA-01C at 13; Attachment RAM-4.

63 D.24-12-039 at 70-71.

64 *Id*. at 75.

the prior year's ERRA Forecast proceeding.[65] This year, SCE again proposes to apply the same methodology for the purposes of 2027 ratemaking.[66]

PG&E proposed changes to its RA valuation methodology to reflect the SoD compliance framework in its 2026 ERRA Forecast proceeding.[67] In that case, PG&E initially proposed to calculate the monthly RA contribution of each resource in its PCIA portfolio based on the weighted hourly average of each of the 24 hours in the SoD capacity calculation.[68] CalCCA objected to PG&E's proposal because of its treatment of storage resources. PG&E's proposal to average storage RA capacity across all 24 hours, including the hours in which storage is charged, did not accurately value the capacity contribution of storage resources because it resulted in a near-zero RA quantity for storage, among other things.[69] CalCCA recommended the Commission address SoD implementation for PCIA ratemaking purposes in a rulemaking, so that the issue could be addressed holistically, including any impacts on both the price and quantity terms used to assess the RA value of PG&E's portfolio.[70] CalCCA recommended in the alternative that the Commission adopt SCE's interim SoD methodology, because that methodology more closely

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65 D.25-12-028, *Decision Approving Southern California Edison Company's 2026 Energy Resource Recovery Account-Related Forecast Revenue Requirement*, A.25-05-008 (Dec. 18, 2025), at 119.

66 *See* SCE Prepared Testimony, A.26-05-006, Exhibit No. SCE-01 at 136-140.

67 A.25-05-011, *Application of Pacific Gas and Electric Company for adoption of Electric Revenue Requirements and Rates Associated with its 2026 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation*.

68 Exh. CalCCA-01C at 12.

69 *Id*. at 13.

70 *Id*.

aligns with the SoD framework and produces results that more closely comport with market realities.[71]

In its Rebuttal Testimony, PG&E proposed certain changes to its SoD methodology to address CalCCA's observation that its original proposal resulted in an unreasonable near-zero RA value for energy storage resources.[72] PG&E proposed to change its weighting approach to apply a 100 percent weighting to the peak load hour in each month and weight the other 23 hours at zero percent.[73] PG&E, however, applied this change to its SoD methodology across all resources (baseload, intermittent, and storage).[74] PG&E's revised SoD proposal did not resolve CalCCA's concerns, nor did it reflect SCE's interim SoD methodology for baseload, intermittent, or storage resources.[75]

Ultimately, in its Final Decision, the Commission determined it was reasonable for PG&E to implement the SoD framework in the 2026 ERRA Forecast, but also agreed with CalCCA's position on energy storage.[76] The Commission found neither of PG&E's proposed SoD RA methodologies (original or revised) to be reasonable, and instead ordered PG&E to "adopt the SCE SoD methodology on an interim basis while awaiting a more comprehensive decision on the implementation of the SoD methodology."[77]

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71 *Id*.

72 *Id*.

73 *Id*.

74 *Id*.

75 *Id*.

76 D.25-12-027, *Decision Approving Pacific Gas and Electric Company's 2026 Energy Resource Recovery Account Related Forecast Revenue Requirement and 2026 Electric Sales Forecast*, A.25-05-011; A.25-09-015 (Dec. 18, 2025), at 37.

77 *Id*. at 37-38.

3. The Commission's Decision in PG&E's 2026 ERRA Forecast Case Resolved RA Valuation for Energy Storage Resources, But PG&E's Methodology for Valuing the RA of Non-Storage Resources Remains Misaligned with the SoD Framework

The Commission's decision in PG&E's 2026 ERRA Forecast case was specific to PG&E's SoD methodology for energy storage resources. The Commission stated:

> PG&E did not provide sufficient evidence that the original and revised proposals would reasonably discount the RA value of *storage resources* by conflating energy with capacity and failing to account for batteries' ability to provide capacity in any hour.[78]
>
> SCE's methodology is simply a method to discount the NQC of *storage resources* to account for the fact that *storage* is not available at its NQC value for 24 hours. PG&E has sufficient information to apply SCE's current methodology for calculating the RA sales; PG&E would apply SCE's current methodology for calculating the RA sales, unsold and retained RA volumes *for storage resources*.[79]

PG&E also understood the Commission's order to refer only to storage resources. In the Advice Letter[80] describing its implementation of the Commission's order into the 2026 PCIA rates, PG&E stated: "Ultimately, in D.25-12-027 the Commission found it was reasonable for PG&E to adopt Southern California Edison's ("SCE's") interim SoD methodology for storage resources only on an interim basis."[81] PG&E further acknowledged that its SoD implementation for the remaining non-storage resource reflected the prior NQC approach when it stated "For all non-storage resources, the NQC values were based on currently approved NQC counting rules."[82]

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78 *Id*. at 37 (emphasis added).

79 *Id*. at 38 (emphasis added).

80 Advice 7820-E, *Notification of PG&E's Implementation of its Slice-of-Day Methodology in Compliance with Decision 25-12-027* (Jan. 22, 2026).

81 *Id*.

82 *Id*. at 1.

Nothing in D.25-12-027 addresses or approves PG&E's approach to SoD implementation for the purposes of valuing RA capacity from non-storage resources. Despite twice approving SCE's interim SoD methodology for all resource types, the Commission has not yet addressed the implementation of the SoD framework for PG&E's non-storage resources. Nor has the Commission yet comprehensively addressed SoD implementation for PCIA ratemaking purposes in a rulemaking. Therefore, it is appropriate for the Commission to address the RA valuation of PG&E's non-storage resources in this case and ensure the quantity term used to determine the RA value of those resources appropriately reflects the Commission's transition to a SoD framework for RA compliance (until such time as the Commission holistically addresses the SoD framework's impact on PCIA ratemaking in a rulemaking).

4. Whereas SCE's Interim SoD Methodology Reflects the Evolution of the RA Program, PG&E's Approach Undercuts It

Unlike SCE, PG&E continues to assess the RA value of intermittent resources based on the resource's peak hour contribution, despite the Commission's transition away from focusing on peak hour NQC in the context of RA compliance.[83] PG&E's methodology is not reasonable, and the Commission should reject it, for two reasons.

First, PG&E's approach leads to a needlessly inconsistent outcome. Under the status quo,[84] the exact same wind and solar resources would be assigned different quantities of retained RA capacity for PCIA ratemaking purposes depending on whether they were procured by PG&E or SCE.[85] Those different retained RA quantities would each be multiplied by the same statewide RA

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[83] Exh. CalCCA-01C at 15; PG&E-01 at 5-12, lines 3-13.

[84] A.26-05-006, SCE Opening Testimony, at 137-139, included as Attachment RAM-4 to Exh. CalCCA-01C.

[85] Exh. CalCCA-01C at 16.

MPB value, resulting in different retained RA values.[86] SCE and PG&E customers receiving a different retained RA value for the same resources solely because they are customers of a different utility would clearly be an inequitable outcome.[87]

Second, PG&E's approach undercuts the Commission's transition to a SoD framework for RA compliance. Again, PG&E's RA valuation methodology uses each resource's output in the single peak hour per month to determine that resource's capacity contribution and the quantity used to value Retained RA in the PCIA.[88] This approach is nearly identical to the NQC-based approach that the SoD framework replaced.[89] That NQC-based approach measured capacity in the single peak hour of each month.[90] PG&E's RA valuation methodology, therefore, effectively circumvents the Commission's effort to evolve the RA program towards considering all hours in the day to ensure resource adequacy.[91] In contrast, SCE's interim SoD methodology—which CalCCA supports—determines the RA quantity associated with intermittent resources by averaging the capacity contribution ("exceedance values") of those resources across all 24 hours in the worst day of the month. In this manner, SCE's interim SoD methodology reflects the RA program's transition to a compliance framework that considers each resource's RA contribution not only during the peak hour, but also during each of the other 23 hours of the day.

The Commission can easily remedy the inconsistency between PG&E and SCE and ensure PG&E's RA valuation methodology better reflects the SoD framework by requiring that PG&E

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86 *Id*.

87 *Id*.

88 *Id*. at 17.

89 *Id*. at 18.

90 *Id*.

91 *Id*.

apply SCE's interim SoD methodology to not only storage, but all resources in its portfolio. To fully align PG&E and SCE's SoD calculations, PG&E should determine the RA contribution of a non-storage intermittent resource by averaging its capacity contribution equally across all 24 hours in the worst day (i.e. day that contains the hour with the highest coincident peak load forecast).[92] Notably, this approach is nearly identical to the one PG&E originally proposed in its initial filing in the 2026 ERRA Forecast case.[93]

5. PG&E's Opposition to SCE's Interim SoD Methodology is Baseless and Misleading

PG&E opposes the application of SCE's interim SoD methodology[94] to non-storage intermittent resources, despite initially proposing a similar methodology in its 2026 ERRA Forecast case. It asserts the Commission's decision in last year's ERRA Forecast case "addressed the interim retained SoD RA methodology for PG&E by explicitly only modifying the treatment of energy storage resources while leaving all remaining elements unmodified, including non-energy storage intermittent resources[.]"[95]

PG&E is correct that D.25-12-027 only modified PG&E's RA valuation methodology for storage resources, but nothing in that Decision expressly addresses PG&E's RA valuation of non-storage resources. In fact, in its reply comments on the Proposed Decision in last year's ERRA Forecast proceeding, PG&E argued that proceeding lacked the record necessary for the

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92 *Id*. at 17.

93 *Id*. at 17, footnote 41 (explaining the only difference is the weighting of the hours. PG&E originally proposed in its 2026 ERRA forecast case to weight the hours by load ratio share, while SCE's methodology provides equal weight to all the hours).

94 PG&E's Rebuttal Testimony references CalCCA's proposed RA valuation methodology, but in response to discovery PG&E concedes CalCCA's methodology is consistent with SCE's interim SoD methodology. Exh. CalCCA-03 (PG&E response to CalCCA DR 10.10).

95 Exh. PG&E-04 at 3-1.

Commission to address the RA valuation of non-storage resources. PG&E stated: "there is no record supporting adoption of SCE's SOD methodology for resources other than energy storage resources nor is there sufficient record for how PG&E would fully calculate retained volumes for any changes beyond energy storage resources . . . Limiting the application of the SCE SOD methodology is the correct outcome as Commission decisions must be based on the record."[96] Those comments—and the language of D.25-12-027 itself—undermine PG&E's suggestion that the Commission "explicitly" addressed the valuation of non-storage RA resources in last year's ERRA Forecast proceeding. Importantly, this year, the record indisputably includes the detail necessary for the Commission to adopt SCE's interim SoD methodology for non-storage resources.

PG&E also asserts SCE's interim SoD methodology would result in "an unjustifiable cost shift to the detriment of PG&E's bundled customers" because that methodology would increase the quantity of RA retained at the MPB. In support of that argument, PG&E presents a convoluted analysis purporting to show that SCE's approach would result in a $224.68 per kW NQC-year "effective MPB" for solar resources, because—according to PG&E—that approach implies "approximately 1.62 MW of retained solar quantity for each MW of peak-hour NQC."[97] PG&E's claims of a cost shift are baseless, and its "effective MPB" analysis is misleading for several reasons.

First, nothing in the record demonstrates the application of SCE's interim SoD methodology would result in an "unjustifiable cost shift" to PG&E's bundled customers. PG&E's allegations of a cost shift rest entirely on the fact that—as CalCCA witness Matley explained—

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[96] A.25-05-011/A.25-09-015 (cons.), *Pacific Gas and Electric Company's (U 39 E) Reply to Opening Comments on the Proposed Decision* at 2-3 (Dec. 4, 2025).

[97] Exh. PG&E-04 at 3-6; 3-7.

the application of SCE's interim SoD method to PG&E's RA portfolio would result in an increase in retained solar RA capacity in 2027.[98] But the mere fact that the application of SCE's interim SoD method would result in an increase in retained solar RA in 2027 does not demonstrate an impermissible "cost shift". The Commission must approve PCIA rates that appropriately reflect the RA value of PG&E's PCIA resources, even if doing so increases the quantity of retained RA.

Second, PG&E's focus on the impact of SCE's interim SoD method on solar RA in 2027 misses the broader implications of that method. PG&E glosses over the fact that the application of SCE's interim SoD method would also result in a decrease in retained wind RA capacity in 2027.[99] More importantly, the results (retained RA capacity) of SCE's interim SoD methodology depend on the average RA contribution of intermittent resources across the 24 hours of the "worst day" of each month. That means SCE's methodology would not necessarily produce an increase in retained Solar RA capacity in every instance (relative to a peak-hour NQC-based method). Further, SCE's methodology would certainly not always result in a ratio of 1.62 MW of retained solar RA for each MW of peak-hour NQC—PG&E derived that ratio entirely from the impact of SCE's method on retained solar RA in 2027.[100] PG&E's assertion that SCE's interim method would produce an effective solar RA MPB of $224.68 per kW NQC is therefore misleading.

Third, PG&E's criticism of SCE's interim SoD method, and its "effective MPB" analysis, is premised on its assertion that the RA MPB is composed primarily of baseload RA transactions, and is therefore effectively a baseload price.[101] According to PG&E, in the PCIA, both solar RA

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98 *Id*. at 3-6 to 3-7.

99 Exh. CalCCA-01C at 17.

100 Exh. CalCCA-07 (PG&E response to CalCCA DR 11.02).

101 Exh. PG&E-04 at 3-5.

and baseload RA get a baseload price (the RA MPB) despite actual market transaction data showing a disparity between the prices each resource type receives,[102] leading to the overstatement of solar RA value under SCE's interim SoD methodology (and even under PG&E's current methodology). But PG&E's assumption is unfounded. PG&E concedes it does not have insight into the full set of RA market transaction data that determines the MPB—its assertion is based solely on its review of Central Procurement Entity transactions.[103] Assuming the RA MPB reflects RA transactions from multiple technology types, it necessarily undervalues baseload resources and overvalues lower-priced resources. Only the Commission is aware of the full set of RA market transaction data that goes into the RA MPB, and therefore the record of this proceeding does not and cannot establish the extent to which the MPB undervalues baseload or overvalues lower-priced resources.

Fourth and finally, PG&E's "Effective MPB" analysis is mathematically unsound. Although PG&E claims its RA valuation methodology is based on the NQC of each Resource, it is in fact based on each resource's peak hour RA contribution. That number diverges significantly from CAISO-published NQC values in several instances.[104] This mismatch undermines PG&E's argument that its methodology aligns with the manner in which the RA MPB is expressed (i.e., a price per kW NQC).

PG&E's "Effective MPB" analysis is ultimately a distraction. The RA MPB is calculated by Energy Division and no party has insight into the full set of RA market transactions informing

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102 *Id*. at 3-7.

103 Exh. CalCCA-02 (PG&E response to CalCCA DR 10.04).

104 *See* Exh. CalCCA-04 and CalCCA-05 (PG&E response to CalCCA DR 10.14, and accompanying attachment).

that price. The RA MPB is not differentiated by technology. Nothing about the RA MPB will change in this proceeding. The only dispute is over the quantity term that must be multiplied by the RA MPB to determine the RA value of PG&E's non-storage resources. The Commission must determine whether using the resource's peak hour RA contribution—per PG&E's proposal—or average contribution over 24 hours—per SCE's interim SoD method, better reflects the RA resource's value in a SoD 24-hour compliance framework. PG&E asserts that RA market prices, and the RA MPB, "continue to be expressed in terms of NQC",[105] but PG&E misses the point. Under the SoD framework, the value of an RA resource, including a solar RA resource, is its contribution towards RA requirements in all 24 hours of the day, across all 12 months of the year. That value is misaligned with the solar resource's peak hour contribution. For instance, during winter months, the Commission's Master Resource Data file reports an NQC near 0 MW for solar RA resources[106] and a buyer would pay for solar RA based on the peak hour NQC volume purchased.[107] But the value of that solar RA, under the SoD framework, would not be zero even in winter months; rather, it would be driven by the resource's contribution across 24 hours. PG&E's focus on the terms in which RA market prices are expressed misses the Commission's transition to a 24-hour RA compliance framework, and the impact of that transition on RA value.

The Commission should therefore adopt SCE's interim SoD method for PG&E's non-storage resources. While CalCCA supports the Commission's holistic evaluation of SoD implementation in the PCIA context in Track 4 of the PCIA rulemaking,[108] the Commission should

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105 Exh. PG&E-04 at 3-6.

106 Exh. CalCCA-06C (PG&E response to CalCCA DR 10.16).

107 Exh. CalCCA-08 (PG&E response to CalCCA DR 11.06).

108 Exh. PG&E-04 at 3-8.

establish an interim approach for PG&E that aligns with SCE and better reflects the SoD framework until the holistic evaluation is complete.

B. WHILE THE COMMISSION SHOULD APPROVE PG&E'S PROPOSAL TO RETAIN AND VALUE UNSOLD RPS VOLUMES, IT SHOULD EXPRESSLY LIMIT PG&E'S ABILITY TO DISPLACE THE RECS APPLIED TOWARDS MINIMUM RETAINED RPS ENTRIES IN PRIOR YEARS

1. Renewable Energy Credits are a Crucial Component of PG&E's Portfolio Value

As mentioned above, a major component of PG&E's overall PCIA portfolio value is its "RPS value"—the ability of its renewable energy resources to satisfy PG&E's RPS requirements.[109] PG&E's compliance with its "Minimum Retained RPS" requirement, adopted in D.20-02-047, directly impacts the RPS value of its PCIA-eligible portfolio. In the event PG&E's bundled net RPS position is forecasted to fall below its bundled RPS target for the applicable ERRA year (which it routinely does), PG&E must retain RECs to make up the shortfall.[110] The RECs PG&E uses to meet its Minimum Retained RPS requirement, the value PG&E assigns those RECs, and the specific PCIA vintages that pay for and receive credit for those RECs directly impact the PCIA rates that customers pay.

RECs remain active in Western Renewable Energy Generation Information System (WREGIS) for a period of three years after their generation, during which they can be sold to another counterparty for its own compliance requirement. PG&E categorizes those RECs as "Unsold RPS" if they have not been used towards PG&E's RPS compliance requirements, and if the RECs have been offered for sale but not sold.[111] After this three-year period, RECs must be

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109 *See supra* Section V.B.

110 Exh. PG&E-01 at 5-12.

111 Exh. CalCCA-01C at 25.

retired in WREGIS, meaning they cannot be sold.[112] Those retired RECS are considered "banked RECs" only if PG&E's quantitative procurement requirement for a compliance period is already met.[113]

2. PG&E and CalCCA Agree PG&E Should Apply Unsold RPS Volumes Towards its 2026 and Forecast 2027 Minimum Retained RPS

PG&E forecasted a shortfall towards its 2027 Minimum Retained RPS requirement in this year's Application, similar to several prior years.[114] PG&E stated in its Prepared Testimony that it intended to cover its Minimum Retained RPS shortfall with banked RECs, in this case pre-2019 Banked RECs.[115] In response, CalCCA recommended PG&E use Unsold RPS volumes that have been retired for RPS compliance purposes before using pre-2019 banked RECs.[116]

On rebuttal, PG&E stated it would apply its Unsold RPS volumes towards its Minimum Retained RPS requirements consistent with CalCCA's recommendation, but not for the reasons CalCCA witness Matley offered in his testimony. According to PG&E, "[f]ollowing a review of applicable RPS compliance rules as expiration dates for Unsold RECs were approaching, PG&E began transferring its Unsold RPS to its WREGIS retirement accounts in order to keep the RECs from expiring and reducing the amount of RECs available for PG&E and the broader market for use towards meeting future RPS compliance requirements."[117] PG&E asserts that it cannot convert those Unsold RECs to Banked RECs because of RPS compliance rules and thus must use them

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112 *Id*.

113 Exh. PG&E-04 at 4-2.

114 Exh. PG&E-01 at 8-17.

115 *Id*. at 8-17 to 8-18; Table 8-4.

116 Exh. CalCCA-01C at 24.

117 Exh. PG&E-04 at 4-3.

towards its expected 2027 RPS shortfall.[118] On August 3, 2026, PG&E filed its RPS Compliance Report for 2025, and that report included 1,643,425 megawatt-hours of RECs retired to PG&E's 2025 WREGIS account.[119] In discovery, PG&E indicated it also retired 1,688,041 megawatt-hours of RECs to its 2026 WREGIS account.[120] PG&E plans on retiring remaining Unsold RECs (489,592 megawatt-hours[121]) to either its 2026 or 2027 WREGIS account.[122] According to PG&E, given that it is currently expected to be physically short of meeting its Compliance Period 5 (2025-2027) requirements, it expects to fully utilize all Unsold RPS towards meeting those requirements.[123] Consistent with D.19-10-001, which requires PG&E to retain RPS based on the volume of RPS used for IOU compliance, PG&E will value those Unsold RPS volumes at the applicable year's MPB.[124] For example, if an Unsold REC is used towards PG&E's 2026 Minimum Retained RPS requirement, PG&E would value the Unsold REC at the 2026 RPS MPB.[125]

CalCCA supports PG&E's use of Unsold RPS volumes towards its Minimum Retained RPS requirement, and agrees those RECs should be retained and valued at the applicable year's RPS MPB. CalCCA will review PG&E's workpapers in the October Update to evaluate PG&E's

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118 *Id*. at 4-2.

119 *Id*. According to PG&E, it retired those RECs to the 2025 WREGIS account on 12/19/2025, 1/15/2026, 2/24/2026, 3/24/2026 and 6/29/2026 – as those RECs approached the 36 month deadline for January through April 2023 vintages (January 2023 vintage RECs needed to be retired by 12/31/2025, for example). Exh. CalCCA-09C (PG&E response to CalCCA DR 10.06).

120 Exh. CalCCA-09C (PG&E response to CalCCA DR 10.06).

121 *Id*.

122 Exh. PG&E-04 at 4-2.

123 *Id*.

124 *Id*.

125 Exh. CalCCA-09C (PG&E response to CalCCA DR 10.06).

use and valuation of Unsold RPS volumes. Below, however, CalCCA discusses a discrete aspect of PG&E's proposal to use Unsold RPS volumes: the impact of its use of Unsold RPS volumes on 2025 Minimum Retained RPS entries, and its displacement of RECs previously used towards its 2025 Minimum Retained RPS requirement.

3. The Commission Should Limit PG&E's Ability to Displace the RECs it Applied Towards Prior Years' Minimum Retained RPS Entries.

In response to CalCCA discovery, PG&E clarified it expects Unsold RPS to displace banked RECs previously used towards 2025 and 2026 RPS requirements.[126] It also acknowledged that the volume of banked RECs being applied in 2025 has been updated and is a different quantity than the volume shown in PG&E's Fall Update in the 2026 ERRA Forecast case (A.25-05-011) and the volume shown in PG&E's 2025 ERRA Compliance proceeding (A.26-02-019).[127]

PG&E chalks these changes up to the multi-year nature of RPS compliance periods. According to PG&E, the multi-year nature of RPS compliance periods (for example, Compliance Period 5 runs from 2025-2027) results in PG&E making updates, corrections, and changes to the REC volumes and specific RECs it uses for bundled customer compliance throughout the period.[128] In other words, even though we are in calendar year 2026, PG&E continues to make changes to the RECs it uses for bundled customer compliance in 2025. This, in turn, necessitates adjustments to Minimum Retained RPS entries for 2025, pursuant to D.19-10-001.[129]

As discussed above, in the interest of portfolio optimization, CalCCA supports PG&E's proposal to use expiring Unsold REC volumes towards its RPS compliance requirements. As

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126 *Id*. (PG&E response to CalCCA DR 10.06(c)).

127 Exh. CalCCA-12 (PG&E response to CalCCA DR 12.02).

128 Exh. CalCCA-13 (PG&E response to CalCCA DR 12.03).

129 *Id*.

PG&E explains, this will "keep the RECs from expiring and reducing the amount of RECs available to PG&E and the broader market for use towards meeting future RPS compliance requirements."[130]

But the Commission should expressly caution that its approval of PG&E's proposal is not a broad authorization for PG&E to unilaterally make changes to its Minimum Retained RPS accounting from prior years. Parties closely examine (and routinely litigate) PG&E's RPS accounting in ERRA Forecast and Compliance cases, including PG&E's Minimum Retained RPS entries and any banked RECs PG&E applies towards the Minimum Retained RPS requirement. PG&E and CalCCA already litigated PG&E's use of banked RECs towards its 2025 Minimum Retained RPS requirement, for example, in the 2024 ERRA Forecast case (A.24-05-009),[131] and the 2025 ERRA Forecast Case (A.25-05-011).[132] In each case, the Commission approved revenue requirements, including PCIA revenue requirements, that reflected the specific RECs PG&E proposed to use towards its Minimum Retained RPS requirement. The Commission should therefore expressly limit PG&E's ability to displace the RECs it previously applied towards a prior year's Minimum Retained RPS requirement, and permit PG&E to make changes for 2025 only to the extent it displaces previously-used banked RECs with expiring Unsold RPS volumes.

CalCCA will review the impact of PG&E's use of Unsold RPS volumes in the October Update, and reserves its right to address and further contest this issue following that review.

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130 Exh. PG&E-04 at 4-3.

131 D.24-12-038 at 16-17.

132 D.25-12-027 at 26-32.

C. THE COMMISSION SHOULD REVISIT THE LOAD FORECAST MEET AND CONFER PROCESS IN THE PCIA OIR

PG&E forecasts sales and peak demand growth across its service area in its annual ERRA Forecast proceedings. That forecast determines which and to what extent bundled and unbundled customers bear the PCIA Revenue Requirement.[133] In developing its sales and peak demand forecasts, PG&E engages in a meet-and-confer with CCAs in its service area, and has historically incorporated CCAs' forecasts into its overall forecasts.[134]

The Commission mandated the ERRA Forecast meet-and-confer process in the 2016 ERRA Forecast proceeding, long before the current wave of hyperscaler data centers that support the modern artificial intelligence buildout.[135] It did not contemplate the significant uncertainty inherent in data center load forecasting.

Accurate forecasts help reduce PCIA rate volatility, whereas significant over- or under-forecasts can harm CCAs and their customers in particular. That is because CCAs and their customers have limited insight into and ability to control PCIA rate swings,[136] and as discussed below, the risk of PCIA rate volatility is likely concentrated into specific PCIA vintage rates paid by CCA customers rather than the PCIA vintage rates paid by bundled customers.[137] In order to improve the accuracy of PG&E's load forecasts and ensure that PG&E and CCAs in its service area remain coordinated in an era of rapid load growth, the Commission should revisit the meet-and-confer process in the pending PCIA rulemaking.

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133 *See* supra Section V.

134 Exh. CalCCA-14C (PG&E response to CalCCA DR 10.01(c)).

135 D.16-12-038 at Conclusion of Law (COL) 3.

136 Exh. CalCCA-01C at 28.

137 *Id*. at 27.

1. Inaccuracies in PG&E's Data Center Load Forecast Can Introduce Volatility into the PCIA

In its ERRA proceedings, PG&E forecasts sales and peak demand sales for the following year. It then allocates the PCIA revenue requirement across all load, bundled and unbundled, according to customer vintage and rate class.[138] In other words, PG&E's load forecasts act as the denominator that converts the PCIA revenue requirement into a PCIA charge per kWh. In the following year's ERRA proceeding, the Commission trues up actual sales against forecasted sales. In the instant Application, PG&E will segment its 2027 sales forecast among customer types, including data centers which fall under the large commercial and industrial customer class.[139]

In his Direct Testimony, CalCCA witness Matley illustrated the impact that one 500 MW data center at 90% load factor can have on PCIA rates for all CCA customers. Witness Matley concluded that if that data center's start of service is delayed by just one year, that would create an approximately 5% discrepancy between forecasted and actual sales.[140] When translated into PCIA rates, that could amount to an approximate increase in $0.004/kWh in the customer vintage for the hypothetical data center and $0.001 kWh for all other vintages.[141] In short, the risks of PCIA rate volatility are not distributed evenly across PG&E's bundled and CCA customers. While PG&E does not agree with the specific calculations witness Matley presents, it nevertheless agrees with his premise, which is that load forecast variance can contribute to undercollections or overcollections in the PABA.[142]

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138 *See* supra Section V.C.

139 Exh. PG&E-01 at 2-11:8-9.

140 Exh. CalCCA-01 at 28:8-15.

141 *Id*. at 29:1-8.

142 Exh. PG&E-04 at 2-7.

2. The Meet and Confer Process Is Outdated and Requires Reform

PG&E has made several important updates to its forecasting methodology that acknowledge that data center load growth is unlike load growth from other large commercial and industrial customers. For example, PG&E has excluded previous historical large data center electricity usage from its regression models, instead accounting for the current wave of data centers separately.[143] PG&E's data center load forecasting relies on its large load interconnection application queue.[144] PG&E takes into account the maturity of projects in its application queue and accounts for certain data-center-specific factors, such as materialization rate and a load factor tied to data centers.[145]

These updates are positive steps. However, the meet-and-confer process between PG&E and CCAs also requires updates in order to ensure PG&E's load forecasts are as accurate as possible, which will in turn reduce the risk of PCIA rate volatility discussed above.

The meet-and-confer process is a required step in each year's ERRA Forecast proceeding during which PG&E works with CCAs to develop load forecasts.[146] In its 2017 ERRA Forecast, PG&E committed to exchange load forecasts with CCAs, working collaboratively to incorporate the most accurate load forecasts into both its ERRA Application and October Update.[147] PG&E correctly assumes that new data center load in CCA service territory will default to CCA service, not PG&E service, unless the customer opts out.[148] That assumption underlines the importance of

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143 Exh. PG&E-01 at 2-4:21-26.

144 *Id*. at 2-11:18-34.

145 *Id*. at 2-11:18–2:12:10.

146 D.16-12-038 at 6. *See also* D.20-03-019 at OP 1.

147 *See* D.16-12-038 at 13-14. *See also* D.20-03-019 at OP 1.

148 Exh. PG&E-01 at 2-12:27-28.

PG&E's annual meet-and-confer process with CCAs, because as discussed above, inaccurate forecasts can cause whiplash for CCAs' customers.

As part of this year's meet-and-confer process, PG&E submitted e-mail requests for load forecasts from the 12 CCAs in PG&E's territory and received forecasts from all 12.[149] For its Prepared Testimony, PG&E only incorporated load forecasts from the seven CCAs that forecasted no data center load growth.[150] Of the five CCAs whose forecasts PG&E did not incorporate, three load forecasts were rejected largely because PG&E disagreed with the respective CCA's data center load forecast specifically.[151] PG&E unilaterally determined that those three CCAs' data center load forecasts relied on outdated assumptions or historical application data.[152] Besides good-faith discussions during the period between PG&E's Prepared Testimony and October Update, those CCAs are entitled to no recourse.[153] The current process provides no pathway to resolve differences in forecast load—when PG&E and a CCA are not able to agree on the data center load forecast, then PG&E will use its own forecast.[154] This potential outcome is problematic because CCAs have unique insight into the certainty and timing of data center loads through the local permitting, zoning, and land-use requirements of the municipalities comprising the CCAs.[155]

The current meet-and-confer process was established a decade ago, well before today's wave of data centers that support artificial intelligence.[156] In the decade since that meet-and-confer

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149 *Id*. at 2-19:16-25.

150 *Id*.

151 Exh. PG&E-04 at 2-4:26-27.

152 Exh. CalCCA-16 (PG&E response to CalCCA DR 10.03(b)).

153 Exh. CalCCA-14 (PG&E response to CalCCA DR 10.01(f)).

154 *See* Exh. CalCCA-01 at 31; Exh. CalCCA-15 (PG&E response to CalCCA DR 10.02).

155 Exh. CalCCA-01 at 32.

156 D.16-12-038 at COL 3.

process, load growth was steady and predictable. The existing meet-and-confer process worked well when PG&E and the CCAs in its service area agreed on load growth forecasts. In the past three October Updates, PG&E incorporated all of the CCA load forecasts into its overall load forecast.[157]

Today, each hyperscaler data center is several times larger than legacy data centers, which amplifies the impact of even one data center customer on the load forecast.[158] In an era when the distribution utility (PG&E) and the load serving entity (a CCA) may disagree about how to model unprecedented load growth – and those disagreements can cause volatility in PCIA rates borne by unbundled customers – the meet-and-confer process must be reformed to ensure accurate forecasts. CCAs are well-positioned to anticipate and model load growth because of their status serving most customer load, access to local government interconnection queue data, and personal relationships with inbound data center customers. A more collaborative process between parties will only strengthen the accuracy and robustness of their composite load forecasts.

The Commission should therefore reform the meet-and-confer process. As a part of that reform process, the Commission should consider treating CCA data center load forecasts as a rebuttable presumption.[159] To the extent PG&E possesses additional relevant information based on discussions with prospective customers or any other source, PG&E should be required to rebut the CCA forecast based on that information (confidentially, if necessary) to prove the accuracy of its conflicting data center load forecast.[160] The Commission should evaluate and adopt reforms to

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157 Exh. CalCCA-14 (PG&E response to CalCCA DR 10.01(c)).

158 Exh. CalCCA-01 at 27:14-21.

159 *Id*. at 32.

160 *Id*.

the data center load forecasting process in the PCIA OIR currently underway. Although this issue is particularly acute and urgent in PG&E's territory at the moment, it will likely impact SCE and San Diego Gas & Electric Company's service territories over time.[161]

VI. UNCONTESTED ISSUES

In addition to the contested issues discussed at length above, CalCCA investigated several other issues raised by PG&E's Application. Below, this brief discusses three of those issues. While these issues are currently uncontested, CalCCA reserves the right to address and contest these issues following its review of PG&E's October Update testimony.

A. RESOURCE ADEQUACY VALUATION METHODOLOGY AND THE IMPACT OF D.26-07-008

In its Supplemental Testimony, PG&E proposed changes in its RA Valuation Methodology stemming from D.26-07-008. In that decision, the Commission adopted reforms that better align RA capacity calculations with the real-world operational experience for three distinct kinds of resources: energy storage resources, energy-only resources, and long-duration storage resources.[162]

1. CalCCA Supports PG&E's Update to Its RA Valuation Methodology for Energy Storage Resources

For energy storage resources, D.26-07-008 modifies the capacity attributable to a battery by accounting for "foldback."[163] Like a phone battery that stops charging at 80% and enters low power mode at 20%, a utility-scale battery system may limit its output when reaching pre-defined thresholds of charge in order to reduce instances of deep discharge, known as foldback. While this

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161 *Id*.

162 Exh. PG&E-03 at 7:6-9.

163 Exh. CalCCA-01 at 20:18–21:2.

maintains battery health, foldback also reduces the continuous capacity that a battery delivers over its full discharge duration. PG&E proposes to change its calculation of battery energy storage to use Maximum Continuous Energy instead of Net Qualifying Capacity to account for foldback.[164]

CalCCA does not object in concept to PG&E's proposed modification because it is reasonable for PG&E to use the most accurate and up-to-date information in calculating the retained RA attributable to battery energy storage systems. However, PG&E has not yet applied its new methodology to its calculation of RA value, and therefore the details of PG&E's proposal will require review in the October Update. CalCCA reserves the right to address and contest PG&E's proposed change to its RA valuation methodology in comments on the October Update.

2. PG&E Has Not Addressed the Directives in D.26-07-008 Related to Energy-Only and Long-Duration Storage Resources

D.26-07-008 also addresses energy-only resources and long-duration storage resources. The Commission made modifications to allow excess energy from co-located energy-only resources to account for certain charging sufficiency requirements.[165] The Commission's change acknowledges that while energy-only resources co-located with energy storage may not have RA capacity value themselves, energy-only resources reduce the need for energy storage systems to utilize RA capacity from other resources.[166] Thus, energy-only resources that are co-located with energy-storage reduce the need for those storage systems to utilize RA capacity from other resources and should therefore not experience the full RA capacity reduction associated with

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164 Exh. PG&E-03 at 7:23-31.

165 D.26-07-008, *Decision Adopting Local Capacity Obligations for 2027-2029, Flexible Capacity Obligations for 2027, and Program Refinements*, R.25-10-003 (July 2, 2026), at OP 8.

166 *Id*. at 38-39.

charging.[167] PG&E has at least one applicable co-located energy-only resource but has not proposed an update to its RA valuation methodology effectuating the Commission's change.[168]

The Commission also modified RA valuations and charging sufficiency requirements for long-duration energy storage resources. Those long-duration energy storage resources can now count their capacity across the 24-hour SoD period up to the resource's capabilities, based on certain other characteristics.[169] That change reflects the fact that long-duration energy storage resources can shift charging across multiple days and preserve a meaningful charging obligation.[170] PG&E has not yet proposed to update its RA valuation methodology to effectuate that change.

While PG&E does not currently have any resources that would qualify as long-duration energy storage,[171] PG&E should nevertheless update its RA Valuation Methodology to more comprehensively address each of the directives from D.26-07-008. In its Rebuttal Testimony, PG&E states that it "intends to implement D.26-07-008 to the extent possible" but also states that "[c]ertain aspects of the decision depend on modifications to the RA Market Reference Data and related implementation steps that are outside of PG&E's control and have not yet been completed."[172] While CalCCA does not contest PG&E's approach at this time, CalCCA reserves the right to further address and contest PG&E's implementation of D.26-07-008 following its review of the October Update.

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167 Id.

168 Exh. CalCCA-01, Attachment RAM-3 (PG&E's Response to DR CalCCA 006-Q009).

169 D.26-07-008 at OP 10.

170 *Id*. at 51.

171 Exh. CalCCA-01, Attachment RAM-3 (PG&E's Response to DR CalCCA 009-Q007).

172 Exh. PG&E-04 at 3-8.

B. INTERIM GENERAL RATE CASE REVENUE REQUIREMENT

PG&E filed its GRC in May 2025 for the 2027-2030 time period.[173] PG&E's forecasted revenue requirement showed a significant $300 million increase in Electric Generation Revenue Requirement attributable to utility-owned generation as compared to 2026, which translates to an increase in the PCIA of approximately $.004 per kWh across all vintages.[174]

The current timeline of the GRC anticipates a final decision by May 2027, too late to include the updated Electric Generation Revenue Requirement in 2027 PCIA rates.[175] PG&E has filed a motion in the GRC to implement Interim Rates effective January 1, 2027, at either 55 percent, 75 percent, or 85 percent of its initial requested revenue requirement increase.[176] The Commission's proposed decision in the 2027 GRC case allows PG&E to charge Interim Rates at 55 percent of its requested revenue requirement for electric generation and distribution.[177] To the extent the Commission approves an interim revenue requirement in the 2027 GRC, PG&E and CalCCA agree that PG&E should implement the electric generation portion of that revenue requirement into 2027 rates.[178]

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173 A.25-05-009, *Application of Pacific Gas and Electric Company for Authority, Among Other Things, to Increase Rates and Charges for Electric and Gas Service Effective on January 1, 2027. (U 39 M)* (May 15, 2025).

174 Exh. CalCCA-01 at 33:11–34:3.

175 *Id*. at 34:3-5.

176 *Id*. at 34:9-11.

177 A.25-05-009, *Proposed Decision of ALJ Fox Authorizing Interim Rate Authority* at 12-13 (Sept. 23, 2026).

178 Exh. PG&E-04 at 5-2.

C. PCIA CALCULATION CORRECTIONS

In its review of PG&E's initial application, CalCCA identified several errors in PG&E's testimony and workpapers.[179] CalCCA raised those errors via discovery, and PG&E confirmed those errors in its responses.[180] PG&E ultimately resolved them in its errata filing submitted July 17, 2026.[181] The errors CalCCA identified are no longer contested. CalCCA notes the discovery process helped identify and resolve these issues, ultimately helping to produce accurate rates.

VII. CONCLUSION

For the foregoing reasons, CalCCA requests the Commission adopt the recommendations listed in CalCCA's Summary of Recommendations. CalCCA reserves the right to modify those recommendations based on updated information presented in PG&E's October Update and to address other issues raised therein via comments on the October Update or any further process the Commission might adopt.

October 21, 2026

Respectfully submitted,



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[179] Fossil Unit Vintaging, Sales Forecast, Retained RPS, and Retained RA. *See* Exh. CalCCA-01 at 35:11–36:14.

[180] *Id*. at 35-36.

[181] Exh. PG&E-02 at 8-27, 12-8, 13-AtchA-2.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S APPLICATION FOR REHEARING OF DECISION 26-09-047

PUBLIC VERSION

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SPECIFICATION OF ERROR[1]

Rehearing should be granted to correct the following errors in D.26-09-047. The Commission:

- × **Misinterprets section 366.2(g)** by finding indifference satisfied for Later Departing Customers on a historical credit provided to a different set of customers – Previously-Departed Customers;

- × **Misapplies section 1731** by finding CalCCA's valuation claim untimely even though the Commission had not previously determined whether customers must receive credit in the PCIA for the subsequent compliance value of Pre-2019 Banked RECs when those RECs are ultimately used;

- × **Fails to satisfy section 1705's findings requirement and lacks evidentiary support** for its conclusion that assigning the entire compliance value of Pre-2019 Banked RECs to Current-Bundled Customers, while providing zero value to Later Departing Customers, satisfies the statutory indifference requirements today;

- × **Fails to address CalCCA's proposed cost-neutral allocation alternative,** which would satisfy the Commission's concern of purported unreasonable cost increases to bundled customers;

- × **Fails to support its laches ruling** with evidence of unreasonable delay or detrimental reliance, despite the Commission's ongoing treatment of the valuation issue as unresolved;

- × **Unreasonably discriminates between customers in violation of section 453** by granting Current-Bundled Customers the entire compliance value of Pre-2019 Banked RECs while denying Later Departing Customers any share of that value solely because they have departed bundled service; and

- × **Unlawfully characterizes relief for Later Departing Customers as "arbitrary"** based on alleged, unproven cost shifts that, if they occurred, would have affected all Then-Bundled Customers, including Later Departing Customers.

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

BEFORE THE PUBLIC UTILITIES COMMISSION
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CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S APPLICATION FOR REHEARING OF DECISION 26-09-047

Pursuant to Public Utilities Code sections 1731(b)(1)[2] and 1732, and Rule 16.1 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure,[3] California Community Choice Association[4] (CalCCA) submits this Application for Rehearing (AFR) of Decision (D.) 26-09-047 (D.26-09-047 or the Decision), issued September 22, 2026.[5] Rule 16.1(a) requires that an application for rehearing be filed within 30 days of the date the Commission mails the decision. This Application is timely filed.

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

[3] *State of California Public Utilities Commission, Rules of Practice and Procedure, California Code of Regulations Title 20, Division 1, Chapter 1* (May 2021): https://webproda.cpuc.ca.gov/-/media/cpuc-website/divisions/administrative-law-judge-division/documents/rules-of-practice-and-procedure-may-2021.pdf; and *Resolution ALJ-485 (*June 11, 2026): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M609/K277/609277261.PDF.

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

[5] D.26-09-047, *Decision Resolving Track Two Issues*, Rulemaking (R.) 25-02-005 (Sept. 22, 2026): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M620/K372/620372336.PDF.

I. INTRODUCTION

The Decision assigns zero value in the Power Charge Indifference Adjustment (PCIA) to renewable energy credits (RECs) generated and banked by the investor-owned utilities (IOU) before January 1, 2019 (Pre-2019 Banked RECs), when those RECs are used to satisfy Renewables Portfolio Standard (RPS) requirements for bundled customers. As a result, community choice aggregator (CCA) customers who paid for a share of those RECs while bundled, but who Later Departing bundled service, receive no benefit for the compliance value realized when the IOUs withdraw the RECs from the bank.

As CalCCA explained at the August 31, 2026, Oral Argument in this proceeding, this result violates the statutory indifference mandates.[6] Section 366.2(g) requires the Commission to compensate CCA customers for "benefits that remain with bundled service customers," unless the CCA customers "are allocated a fair and equitable share of the benefits." Later Departing Customers will have paid for RECs they will never get to use or receive credit for, while Current-Bundled Customers will receive the entire compliance benefit—including the share paid for by customers who subsequently departed. The Decision thus confers a windfall on Current-Bundled Customers at Later Departing Customers' expense.

This AFR identifies multiple legal errors, each independently requiring rehearing and correction of the Decision's central holding: the denial to CCA customers of credit through the PCIA for the compliance value of Pre-2019 Banked RECs they funded. The Decision rests on an erroneous interpretation of the indifference requirements, unsupported findings and legal conclusions, and procedural grounds that conflict with the Commission's longstanding treatment

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[6] *See August 31, 2026 Oral Argument Reporters' Transcript,* R.25-02-005, Vol. 2 (Pages 215-275) (Sept. 3, 2026) (OA Tr.), at 218:13-14: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M617/K522/617522978.PDF.

of the Pre-2019 Banked REC valuation issue as unresolved. It also fails to address an alternative allocation proposal that could preserve indifference without increasing bundled customers' costs.

Rehearing should be granted to correct the following errors. The Commission:

- × **Misinterprets section 366.2(g)** by finding indifference satisfied for Later Departing Customers on a historical credit provided to a different set of customers – Previously-Departed Customers;
- × **Misapplies section 1731** by finding CalCCA's valuation claim untimely even though the Commission had not previously determined whether customers must receive credit in the PCIA for the subsequent compliance value of Pre-2019 Banked RECs when those RECs are ultimately used;
- × **Fails to satisfy section 1705's findings requirement and lacks evidentiary support** for its conclusion that assigning the entire compliance value of Pre-2019 Banked RECs to Current-Bundled Customers, while providing zero value to Later Departing Customers, satisfies the statutory indifference requirements today;
- × **Fails to address CalCCA's proposed cost-neutral allocation alternative,** which could satisfy the Commission's concern of purported unreasonable cost increases to bundled customers;
- × **Fails to support its laches ruling** with evidence of unreasonable delay or detrimental reliance, despite the Commission's ongoing treatment of the valuation issue as unresolved;
- × **Unreasonably discriminates between customers in violation of section 453** by granting Current-Bundled Customers the entire compliance value of Pre-2019 Banked RECs while denying Later Departing Customers any share of that value solely because they have departed bundled service; and
- × **Unlawfully characterizes relief for Later Departing Customers as "arbitrary"** based on alleged, unproven cost shifts that, if they occurred, would have affected all Then-Bundled Customers, including Later Departing Customers.

The Commission should grant rehearing and adopt a method that accounts for the compliance value of Pre-2019 Banked RECs when the IOUs use them for bundled customers' RPS compliance. This AFR identifies each challenged ruling, the governing law, the supporting record, and the resulting prejudice. CalCCA seeks application of the statutory indifference

requirements to a compliance benefit the IOUs and their bundled customers realize today, without reopening rates previously made final.

II. BACKGROUND AND PROCEDURAL HISTORY

A. Retail Electricity Choice and the Statutory Indifference Framework

Through the passage of Assembly Bill (AB) 117 in 2002, the California Legislature authorized Community Choice Aggregation, broadening opportunities for retail electric competition previously allowed only through Direct Access (DA) service via Electric Service Providers (ESPs).[7] Instead of receiving all services (i.e., generation, transmission, distribution, and other services) from their IOU (as a bundled customer), CCA customers receive generation service from their local CCA, and continue receiving transmission, distribution, and all other services from the IOU (unbundled or departed load customer).[8] Today, 25 CCAs are in operation in California serving more than 15 million customers.[9]

California law requires that the Commission ensure customer indifference as a result of retail choice. This statutory indifference has three related requirements:

- Bundled customers should not experience cost increases due to the implementation of a CCA program or a customer choosing to receive service from other providers;[10]
- Departed load should not experience cost increases due to an allocation of costs not incurred on behalf of the departed load;[11] and
- Net unavoidable electricity costs paid by CCA customers must be reduced "by the value of any benefits that remain with bundled service customers, unless the [CCA] customers . . . are allocated a fair and equitable share of those benefits."[12]

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7 AB 117 (Stats. 2002, ch. 838).

8 Brian Dickman, *Track 2 Direct Testimony of Brian Dickman on Behalf of the California Community Choice Association* (Mar. 2, 2026) (Ex. CCA-01), at 4:20-23: https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/R2502005/8997/601158208.pdf. DA/ESP customers are also unbundled or departed load customers.

9 *Id.* at 4:23-24.

10 Sections 365.2, 366.2(a)(4), and 366.3.

11 *Ibid*.

12 Section 366.2(g).

B. Commission-Established Indifference Methodology: The Power Charge Indifference Adjustment

The PCIA is the tool the Commission adopted "to equalize cost sharing" and ensure indifference between these two groups of customers.[13] When customers of IOUs depart from bundled service and receive their electricity from a non-IOU provider, such as a CCA, the PCIA mechanism results in "those customers remain[ing] responsible for costs previously incurred on their behalf by the IOUs — but only those costs."[14] Consistent with the indifference statutes, the PCIA also conveys to departed load customers the value of resource attributes retained by the IOU for bundled customers.[15]

PCIA rates are established to recover the IOU's above-market costs related to PCIA-eligible resources (Indifference Amount).[16] The Indifference Amount is the difference between the cost and value of the IOU's supply portfolio.[17] The PCIA therefore tracks both: (a) the costs of resources; and (b) the value of the benefits provided by the IOUs' PCIA-eligible portfolios and retained by the IOU for bundled customers.[18] Since D.11-12-018, the value of the IOUs' supply portfolios has been derived from administratively determined proxy values that are intended to estimate the value the resource portfolio attributes could provide: Energy Value, RPS

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13 *See* D.18-10-019 at 3; Ex. CCA-01 at 6:3-5.

14 *Scoping Memo and Ruling of Assigned Commissioner,* R.17-06-026 (Sept. 25, 2017), at 2; *see also* D.18-10-019, *Decision Modifying the Power Charge Indifference Adjustment Methodology,* R.17-06-026 (Oct. 11, 2018), at 3; Ex. CCA-01 at 6:5-8.

15 Ex. CCA-01 at 6:8-9.

16 *Id.* at 6:10-11.

17 *Id.* at 6:11-13.

18 *Id.* at 6:16-18.

Value, and Resource Adequacy (RA) Value.[19] These values are calculated by multiplying eligible resource output (quantities) by the relevant market-price benchmarks (MPB) (prices).[20]

C. RPS-Eligible Resources Produce Value Through RECs the IOUs Use Immediately or Bank for Later RPS Compliance

RPS value, as one of the components of IOU portfolio value, estimates the financial value attributable to RECs generated by PCIA-eligible resources and retained by the IOU for bundled customer RPS compliance obligations.[21] This RPS value is determined by applying the RPS MPB to the quantity of RECs used by the IOU.[22] To the extent an IOU uses RECs to meet the needs of bundled customers, the PCIA design requires bundled customers to "purchase" departed load customers' share of the RECs. This conveys the value of the RECs to departed load and ensures indifference according to California law.[23] That "purchase" is priced at the RPS MPB.[24]

RPS value is unique (when compared to energy and RA) because IOUs can place a REC into a "bank," which means that the REC can be saved to be used for a later compliance period.[25] Therefore, the IOU can choose to separate in time a REC's generation (and banking) period from when the REC is used for RPS compliance.[26]

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[19] *See, e.g.,* D.11-12-018 at 9-10, Ordering Paragraph (OP) 5, and OP 8; D.19-10-001 at 6 ("Market Value is the estimated financial value, measured in dollars, that is attributed to a utility portfolio of energy resources for the purpose of calculating the [PCIA] for a given year."). D.23-06-006 subsequently also required Energy Division to calculate a separate MPB for Greenhouse-Gas Free (GHG-Free) energy. *See also* Ex. CCA-01 at 6:18-7:2.

[20] Ex. CCA-01 at 7:2-3.

[21] *Id.* at 8:15-17 (citing D.19-10-001 at 6, 26; D.11-12-018 at 8, 10, and Conclusion of Law (COL) 3).

[22] *Id.* at 8:17-18. RPS value may also include revenue received when the IOU's RECs are sold to third parties.

[23] *Id.* at 8:18-9:1.

[24] *Id.* at 9:1-2.

[25] *Evidentiary Hearing Reporters' Transcript,* R.25-02-005, Vol. 1 (Pages 1-214) (EH Tr.) 29:2-11; 30:9-14 (Joint IOU Panel [Brown, Morien, Pulgar]): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M608/K212/608212027.PDF.

[26] *Ibid.*; Ex. CCA-01 at 9:3-5; *see* section 399.13(a)(5)(B) (ordering the Commission to adopt "Rules permitting retail seller to accumulate, beginning January 1, 2011, excess procurement in one compliance period to be applied to any subsequent compliance period.").

D. To the Extent the IOUs Withdraw Pre-2019 Banked RECs for Bundled Customer RPS Compliance After the Year in Which They Were Generated and Banked, Payment for the RECs and Realization of the Benefits Occur at Different Times

Prior to 2019, bundled customers paid through generation rates for the cost of IOU generation resources, including RPS-eligible resources that generated RECs, whether those RECs were used for compliance in the year generated or banked for later use.[27] Customers who had already departed bundled service (Previously-Departed Customers) also paid for a share of these IOU generation resources on a vintaged basis through PCIA rates.[28] Each year, the IOUs would forecast the quantity of RECs from PCIA-eligible resources that would not be sold to third parties, and these RECs were valued in the PCIA for Previously-Departed Customers using the RPS MPB in the year of generation.[29] The value was credited to the PCIA, providing a partial offset to the costs paid by Previously-Departed customers.[30] Decision 11-12-018 therefore delineated payment for the RECs when they were generated and banked between Previously-Departed Customers (i.e., who received a credit for their share of the RECs) and customers who were bundled at the time the REC was generated (Then-Bundled Customers) who paid for the RECs in their generation rates.[31] All Then-Bundled therefore paid for any RECs the IOUs banked for later use.[32] Therefore, while Then-Bundled Customers had access to those RECs for later use, D.11-12-018 did not address the possibility that additional Then-Bundled Customers may depart for unbundled service (i.e., becoming Later Departing Customers) and that their portion of the RECs remained in the bank, paid for but not used (at which time they would

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27 Ex. CCA-01 at 9:8-10.
28 *Id.* at 9:10-12.
29 *Id.* at 9:12-14.
30 *Id.* at 9:14-16.
31 *Id.* at 9:8-17.
32 *Id.* at 9:16-17.

provide value). In fact, the Decision at issue here even states that "[t]he Commission did not recognize "Later Departing [Customers]" as a customer group in D.11-12-018 in any way."[33]

In 2019, the Commission refined D.11-12-018's requirements, deferring payment by bundled customers for banked RECs until they are used for compliance and, likewise, deferring compensation to departing load for those RECs until they are used for compliance.[34] These new requirements recognized that customers do not realize the value of the IOUs' banked RECs until those RECs are used for bundled customer RPS compliance (or sold).[35] At that time, bundled customers are charged for the cost of those RECs at the then current market value (i.e., the RPS MPB) and an offsetting credit is included in the PCIA.[36] This credit to the PCIA for the value of RECs compensates departed load customers for the value of their share of the RECs.[37] These refinements, however, did not upset the original accounting for Pre-2019 Banked RECs.[38] Decision 19-10-001 only applied the new accounting methodology to valuation of RECs generated and banked after the decision (i.e., Post-2018 RECs), and did not address the Pre-2019 Banked REC valuation methodology.[39]

E. The Four Relevant Customer Groups in the Context of Pre-2019 Banked RECs

Four partially overlapping categories of customers exist in the context of Pre-2019 Banked RECs:

- **Previously-Departed Customers –** customers who had already departed at the time the RECs were banked;

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33 Decision, Finding of Fact (FOF) 4.
34 *See generally* D.19-10-001.
35 *Id.* at 35.
36 Ex. CCA-01 at 10:9-12.
37 *Id.* at 10:12-13.
38 *Id.* at 10:13-14.
39 *Id.* at 10:13-16.

- **Then-Bundled Customers –** customers who were bundled at the time the RECs were banked (these customers are, today, either Current-Bundled or Later Departing Customers);

- **Current-Bundled Customers –** customers who are currently bundled and on whose behalf the banked RECs are now being used; and

- **Later Departing Customers –** customers who departed after the RECs were banked and who no longer remain in the group of customers on whose behalf the RECs are now being used.[40]

Later Departing Customers paid for a share of the Pre-2019 Banked RECs when they were Then-Bundled Customers, but upon their departure from bundled service were not paid for those RECs which remained in the bank, ready for future use.[41] These Later Departing Customers number in the millions, constituting a significant portion of the customers in each IOU's service territory—between 29 percent and 66 percent, depending on the IOU and the REC generation year.[42] Thus, although the relationship between customer count and load is not one-to-one, the corresponding share of each IOU's pre-2019 REC bank that was paid for by Later Departing Customers, but for which Later Departing Customers will not receive any benefit, is similarly significant.

Recently, the Joint IOUs began to use Pre-2019 Banked RECs to meet their RPS compliance requirements for Current-Bundled Customers, thus avoiding the purchase of

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[40] *Id*. at 10:23-11:4, 12:3-8.

[41] *Id*. at 13:9-11. During Oral Argument on the Track 2 Proposed Decision, CalCCA Counsel Tim Lindl provided a practical example: "Let's pretend it's 2017; you're a bundled customer; you live in Woodland [California], and you're going to pay your ERRA rates going forward. So you've paid for RPS compliance. There are other departed customers: [in] Sonoma, Marin, et cetera. You're a bundled customer. So you have to pay those customers a credit for the renewable value; right. So that's the bargain at the time is between you, as a bundled customer, and them, as departed customers. In 2018, [the CCA] Valley Clean Energy Alliance [VCE] forms and you are opted in [to be served by VCE], and now you are a departed customer; right. So now you've paid for a REC that you can't get any benefit from. And you don't get any benefit from until the Utilities use that REC in the future. So now you're not benefiting from something that you've paid for previously unless you get a credit today. Another way of say this is in 2017, the issue was between then departed customers and bundled customers, but you were a bundled customer at that time. This issue is different. You never got a credit in 2017, and you won't get a credit under the PD."). OA Tr. at 250:4-24.

[42] Ex. CCA-01 at 13:11-12 to 14:1-2.

additional RECs at current market prices.[43] As a result, Current-Bundled Customers receive the value of the Pre-2019 Banked RECs.[44] However, Later Departing Customers still have not received any value for the Pre-2019 Banked RECs for which they also paid when they were Then-Bundled Customers—neither the 'avoided cost' value Current-Bundled Customers enjoy nor the ability to use those banked RECs for Later Departing Customers' own RPS compliance.[45] These Later Departing Customers will not otherwise receive any benefit when the IOUs use the RECs for Current-Bundled Customer compliance needs.[46] Absent a credit to the PCIA or an allocation of these Pre-2019 Banked RECs, Later Departing Customers will not receive a share of the value of those RECs, despite paying for a share of their costs.[47]

CalCCA proposed valuing the RECs at the RPS MPB through a vintage-specific credit in the PCIA.[48] The IOU would record the credit to the PCIA vintage in the year the RECs were generated, which would avoid any double credit to customers that had already departed.[49] As an alternative, CalCCA proposed that the Commission could utilize section 366.2(g)'s "allocation" option to achieve indifference regarding the IOUs' use of Pre-2019 Banked RECs.[50] To achieve indifference using this pathway, the Commission would require the IOUs to proportionately allocate Pre-2019 Banked RECs to the customers who paid for these RECs via a decrement to

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43 *Id*. at 14:3-5.
44 *Id.* at 14:5-6.
45 *Id.* at 14:6-9.
46 *Id.* at 14:9-11.
47 *Id.* at 14:11-13.
48 *Id.* at 16:21-24.
49 *Id.* at 16:21-24. By recording the credit to the PCIA vintage in the year the RECs were generated, already departed customers will not get a second credit. Therefore, if you departed in 2014, and a REC was generated in 2015, you would not receive a credit. *See* OA Tr. 255:8-16.
50 Brian Dickman, *Track 2 Direct Testimony of Brian Dickman Addressing the Staff Report and Proposals on Pre-2019 Banked Renewable Energy Credits on Behalf of the California Community Choice Association* (May 12, 2026) (Ex. CCA-03), at 22:3-14: https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/R2502005/9283/606453739.pdf.

the applicable load-serving entity's (LSE) RPS Procurement Need.[51] This alternative, allowed by section 366.2(g), avoids any arguable cost increase for bundled or unbundled customers because the attributes simply get allocated rather than requiring bundled customers to compensate departed customer for their value and is a simple accounting modification.[52] While the Decision addresses CalCCA's valuation proposal in its finding of zero value for Pre-2019 Banked RECs in the PCIA, it did not make any findings rejecting CalCCA's allocation proposal.

F. After Years of Considering and Valuing Pre-2019 Banked RECs on an Interim Basis, Track 2 Was Established to Resolve the Disputed Treatment

The Commission considered differing treatments of Pre-2019 Banked RECs in multiple Energy Resource Recovery Account (ERRA) forecast proceedings, as well as in the last PCIA proceeding, R.17-06-026. In fact, the Decision constitutes the *thirteenth* decision contemplating how to resolve this issue.[53] The Commission's treatment of this issue over many years demonstrates that it remained unresolved until this Track 2 was established to address this "exigent" issue:[54]

- Several decisions described their treatment of this issue as interim, limited to the proceeding, or pending resolution in a rulemaking;[55]

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51 *Id.* at 6-8.

52 *See* OA Tr. at 246:17-247:19; *see also* Ex. CCA-03 at 22:3-14 (describing CalCCA allocation proposal).

53 OA Tr. at 222:14-16.

54 *Assigned Commissioner's Amended Scoping Memo and Ruling,* R.25-02-005 (Feb. 3, 2026), at 2.

55 *See* D.25-12-028, *Decision Approving Southern California Edison Company's 2026 Energy Resource Recovery Account-Related Revenue Requirement Forecast,* A.25-05-008 (Dec. 18, 2025), at 111-113, COL 14 ("interim"); D.25-12-027, *Decision Approving Pacific Gas and Electric Company's 2026 Energy Resource Recovery Account Related Forecast Revenue Requirement and 2026 Electric Sales Forecast,* A.25-05-011 (Dec. 18, 2025), at FOF 15 ("on an interim basis for the purpose of this decision"); D.24-12-039, *Decision Approving Southern California Edison Company's 2025 Energy Resource Recovery Account-Related Forecast Revenue Requirement,* A.24-05-007 (Dec. 19, 2024), at 68 (approving treatment "for this proceeding"); D.24-08-004, *Decision Denying Petition for Modification of Decision 23-06-006,* R.17-06-026 (Aug. 1, 2024), at 5 (denying SCE's Petition for Modification and saying the Commission "may consider the issue in a future rulemaking"); D.23-11-094, *Southern California Edison Company's 2024 Energy Resource Recovery Account Forecast,* A.23-06-001 (Nov. 30,

- SCE twice agreed with CCAs during the ERRA Forecast proceedings that post-2018 RECs should be utilized first while awaiting a Commission decision on valuation of Pre-2019 Banked RECs;[56]

- PG&E valued pre-2019 banked RECs at the RPS MPB in its 2023, 2024, and 2025 ERRA Forecast proceedings, and this approach was adopted by the Commission;[57]

- Prior to D.23-06-006, which closed R.17-06-026, the Commission asked parties what issues remained unresolved and both the IOUs and CCAs identified Pre-2019 Banked REC valuation as an outstanding, unresolved issue, but the Commission closed the rulemaking without addressing it;[58]

- SCE filed a Petitioned for Modification of D.23-06-006 following the closure of R.17-06-026, and the Commission answered that it may consider the issue in a future rulemaking;[59] and

- The 2026 PG&E ERRA Forecast Decision stated that D.19-10-001 did not address this issue.[60] In fact, the Decision denying rehearing (issued after the Track 2 Decision) confirms that "D.19-10-001 does not conclusively resolve what methodology should be used to value pre-2019 banked RECs."[61]

During Track 2, the ALJ issued a Ruling with an Energy Division Staff Report regarding Pre-2019 Banked REC valuation.[62] Energy Division noted in the Staff Report that:

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

2023), at 60 ("interim"); *see also* D.26-10-037 at 13 (summarizing the Commission's approach prior to the Track Two decision as "adopting interim approaches" pending a comprehensive review of this issue).

56 OA Tr. at 221: 22-24.

57 *See* D.22-12-044; D.23-12-022; D.24-12-038; *see* D.26-10-037 at 12 ("[T]he Commission has previously approved PG&E's request to value pre-2019 banked RECs at the RPS Adder.").

58 OA Tr. at 221:25-222:4.

59 *Id*. at 222:5-9.

60 D.25-12-027 at 31.

61 D.26-10-037 at 8; *see also* D.26-10-036 at 10 ("D.19-10-001 did not resolve whether the valuation methodology for RECs banked prior to [2019] should also be modified."), and at 11 (D.19-10-001 "did not clarify whether the Commission should continue to treat pre-2019 banked RECs in the same manner it had prior to the 2019 decision.").

62 *Administrative Law Judge's Ruling Issuing Staff Report,* Attachment 2, R.25-02-005 (Mar. 27, 2026) (Staff Report).

> adders at the time, whereas remaining banked RECs will serve to meet RPS compliance for the remaining 20% of bundled load.[63]

The windfall to the utilities' bundled load customers described in the Staff Report resulted in Energy Division concluding that "ED staff observe that these banked RECs—which were funded in part by Later Departing Customers—*do have value in that they can be used for compliance*."[64] Energy Division, however, determined that finding the appropriate value for those RECs is "challenging" because "determining and calculating an opportunity cost or hedging value is deeply intertwined in complex procurement planning and market processes."[65] Therefore, Energy Division developed four proposals not on the basis that those proposals would meet indifference, but rather as a "potential compromise[] that may better ensure indifference by reducing the impact on both sets of customers."[66] While CalCCA questioned during the proceeding whether a compromise approach can meet the indifference requirements,[67] Energy Division's finding that value must be recognized is significant.

Along with the Staff Report, parties including CalCCA and the IOUs submitted two sets of Testimony (Direct and Rebuttal) and Opening and Reply Briefs, and participated in an Evidentiary Hearing over Pre-2019 Banked REC valuation. The Public Advocates Office of the California Public Utilities Commission (Cal Advocates) also submitted Reply Testimony that "[i]f Pre-2019 Banked RECs provide current RPS compliance value to bundled customers, that value constitutes a benefit remaining with bundled service that [Section 366.2(g)] requires be fairly and equitably credited to departed load."[68] Cal Advocates also states that "[a]pplying a

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63 *Id*. at 5.
64 *Id.* at 8 (emphasis added).
65 *Id*.
66 *Id*. at 9.
67 Ex. CCA-03 at 20:17 to 21:12.
68 Ex. CalAdv-01 at 2:22-24.

non-zero value to Pre-2019 Banked RECs is not a "re-valuation" because Banked RECs have been included as a debit to the IOUs' revenue requirement, but they do not provide their full value to customers until used for compliance."[69] Cal Advocates questioned whether the RPS MPB is an accurate valuation of Pre-2019 Banked RECs, but encouraged the Commission to fairly allocate the benefits to ensure the Commission doesn't "undermine [its] statutory obligation to maintain customer indifference."[70] Similarly, the Direct Access Customer Coalition and Alliance for Retail Energy Markets, representing direct access customers and Electric Service Providers, also submitted a Reply Brief stating that "Pre-2019 RECs contain value that must be accounted for."[71]

G. The Decision Denies Any Value to Later Departing Customers for IOU Use of Pre-2019 Banked RECs for Current-Bundled Customer RPS Compliance

After seven months of litigation just in Track 2 over the value of Pre-2019 Banked RECs, the Commission issued D.26-09-047, denying any value, and finding that:

- The indifference mandates do not require any "additional" valuation for Pre-2019 Banked RECs when they are used for bundled customer compliance because the Commission-determined benefits of the RECs were "fully allocated" under the pre-2019 methodology set forth in D.11-12-018 and that "is all the indifference mandates required";[72]
- CalCCA's proposal is inconsistent with D.19-10-001, which "exempted Pre-2019 Banked RECs from the new PCIA methodology that would require bundled customers to credit the PCIA for RECs used to satisfy bundled customer compliance requirements only in the years they are used for that purpose," and

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69 *Id*. at 5:8-10.

70 *Id*. at 6:22 to 8:13. While Cal Advocates acknowledged Pre-2019 Banked REC value during the proceeding, during Oral Argument on the Proposed Decision Cal Advocates voiced support for the Proposed Decision, stating that the PD's determinations "modify some of the assumptions upon which Cal Advocates' previous recommendations and testimony were based." OA Tr. at 226:5-227:7.

71 *Reply Brief of the Direct Access Customer Coalition and Alliance for Retail Energy Markets,* R.25-02-005 (June 25, 2026), at 2.

72 Decision at 10, 28-29, 30, 31-32, COL 1, 3, and 4.

requiring bundled customers "to pay an additional cost to use the RECs now would be inconsistent with the indifference statutes";[73]

- "Requir[ing] redress of this single, alleged cost shift that occurred under a prior methodology now, years after the alleged cost shift was adopted in Commission rules, would be arbitrary";[74]

- CalCCA "is essentially arguing that the RPS valuation methodology adopted by D.11-12-018 was legal error . . . However, neither CalCCA nor its members sought rehearing of D.11-12-018 on these bases" or sought rehearing or filed a petition for modification of D.19-10-001, and therefore CalCCA's claims are untimely; and

- CalCCA's claim is barred by the equitable doctrine of laches, given the unreasonable delay in challenging D.19-10-001, and the prejudice of that delay on other stakeholders who relied on the prospective nature of D.19-10-001.[75]

As set forth below, all of these findings constitute error.

III. STANDARD OF REVIEW

Per Commission Rule 16.1(c) and sections 1731 and 1732, an AFR must set forth specifically the grounds on which a decision in question is "unlawful or erroneous" with references to the law and the record. The purpose of an AFR is "to alert the Commission to a legal error, so that [it] may correct it expeditiously"[76] and to "provide[] the Commission with sufficient notice to respond to [the] claims."[77]

Sections 1757 and 1757.1 govern later judicial review, not the Commission's rehearing procedure. Section 1757 applies to complaint or enforcement proceedings and ratemaking or licensing decisions of specific application addressed to particular parties; section 1757.1 applies to proceedings outside that category. Because this Decision issued in a rulemaking, section 1757.1 may govern any later writ review. This AFR preserves the section 1757 grounds in the

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73 *Id*. at 10-11, 32-33.
74 *Id*. at 11.
75 *Id*. at 36-39.
76 Commission Rule 16.1(c).
77 *Util. Consumers' Action Network v. Pub. Util. Comm.* (2010) 187 Cal.App.4th 688, 705.

alternative if the Decision is treated as a ratemaking decision of specific application, while also identifying the corresponding section 1757.1 grounds.

If section 1757 governs, the principal review grounds asserted here, as described more fully below are:

- ¥ Action without or in excess of the Commission's statutory powers or jurisdiction (Section 1757(a)(1));
- ¥ Failure to proceed as required by law (Section 1757(a)(2));
- ¥ A decision unsupported by its findings (Section 1757(a)(3));
- ¥ Findings unsupported by substantial evidence in light of the whole record (Section 1757(a)(4)); and
- ¥ Abuse of discretion (Section 1757(a)(5)).

If section 1757.1 governs because this is a rulemaking decision, the corresponding grounds, as described more fully below, are:

- ¥ Abuse of discretion (Section 1757.1(a)(1));
- ¥ Failure to proceed as required by law (Section 1757.1(a)(2));
- ¥ Action without or in excess of the Commission's statutory powers or jurisdiction (Section 1757.1(a)(3)); and
- ¥ A decision unsupported by its findings (Section 1757.1(a)(4)).

IV. GROUNDS FOR REHEARING

The Decision directs zero-dollar valuation for all Pre-2019 Banked RECs for purposes of the three IOUs' annual PCIA indifference amounts going forward, and also applies that method immediately to the 2027 ERRA October Updates, impacting 2026 true-ups and 2027 forecast rates.[78] The Decision rests on multiple prejudicial legal errors, each independently requiring

[78] Decision at OP 1-2.

rehearing and vacatur of the zero-dollar valuation. The legal errors are summarized below, and described in more detail herein:

A. The Decision Misinterprets Section 366.2(g) by Finding Indifference Satisfied by a Historical Credit to Previously-Departed Customers

Section 366.2(g) requires the Commission to account for "any benefits that remain" with bundled customers. The generation-year market-value credit to Previously-Departing Customers and a later compliance value for Later Departing Customers are distinct benefits, realized at different times and by different customer groups. The Commission cannot treat the historical credit as compensation for the later benefit without record-supported findings that establish that relationship.

The statutory misinterpretation constitutes Commission action beyond its authority and failure to proceed as required by law under section 1757(a)(1) and (2); or section 1757.1(a)(2) and (3), if the Decision is reviewed as a rulemaking decision.

B. The Decision Misapplies Section 1731 By Finding CalCCA's Claim for Valuation of Pre-2019 Banked RECs Untimely

Neither D.11-12-018 nor D.19-10-001 determined whether Later Departing Customers are entitled to a share of the compliance value when the IOUs later use Pre-2019 Banked RECs for their bundled customer RPS compliance. CalCCA therefore was not required to seek rehearing of those decisions under section 1731 on an issue the Commission did not decide. The present Decision makes that determination, and this AFR timely challenges it.

The untimeliness ruling and the incorrect application of section 1731 to a matter not determined in the earlier proceedings constitute a failure to proceed as required by law and abuse of discretion, under section 1757(a)(2)and (5); or section 1757.1(a)(1) and (2), if section 1757.1 governs.

C. The Decision Fails to Satisfy Section 1705's Findings Requirement and Lacks Adequate Evidentiary Support

The Decision fails to make the findings required by section 1705 to support its conclusion that assigning the entire compliance value to Current-Bundled Customers while providing zero value to Later Departing Customers for Pre-2019 Banked RECs satisfies the statutory indifference requirements today. Section 1705 requires the Decision to "contain separately stated, findings of fact and conclusions of law on all issues material to the order or decision."

The Decision thus fails to proceed as required by law, is not supported by its findings, and the findings lack substantial-evidence support, under section 1757(a)(1), (3), and (4); or under section 1757.1(a)(2) and (4), if section 1757.1 governs.

D. The Decision Fails to Address CalCCA's Proposed Cost-Neutral Allocation Alternative, Violating Section 1705's Findings Requirement and Constituting an Abuse of Discretion

The Commission violates section 1705 and abuses its discretion by failing to consider CalCCA's proposed allocation alternative, which would not result in any purported cost increases, despite concluding that it cannot value Pre-2019 Banked RECs at anything other than zero given that would result in "unreasonable rates for bundled customers" and an increase in their costs.[79]

Failure to address the allocation alternative constitutes a failure to proceed in the manner required by law, is not supported by the findings, the findings are not supported by substantial evidence in light of the whole record, and is an abuse of discretion under section 1757(a)(2)–(5); or section 1757.1(a)(1) and (2), and (4), if section 1757.1 governs.

[79] Decision at 29; OA Tr. at 245:23-25 (Commissioner Baker stating at Oral Argument that "we really don't want to impose costs on anyone right now" and "Let's just try to solve this in a way that doesn't cost anybody – any ratepayers any money").

E. The Laches Ruling is Unsupported and Inconsistent with the Commission's Treatment of the Issue as Unresolved

CalCCA has repeatedly challenged zero valuation when the Pre-2019 Banked REC issue arose; the Commission repeatedly resolved the issue on an interim or proceeding-specific basis and set Track 2 to decide it. The IOUs themselves said there was no guidance for accounting for banked RECs used for compliance. The Decision does not identify the specific detrimental reliance caused by CalCCA's conduct required to reach its laches conclusion.

With its laches ruling, the Commission does not proceed as required by law, the Decision is not supported by its findings, the findings are not supported by substantial evidence in light of the whole record, and the decision constitutes an abuse of discretion under section 1757(a)(2)–(5); or section 1757.1(a)(1), (2), and (4), if section 1757.1 governs.

F. The Decision's Zero Valuation Creates Unreasonable Discriminatory Treatment of Later Departing Customers and Current-Bundled Customers Under Section 453

Customers who paid for the same RECs receive materially different treatment in violation of section 453 based solely on whether they have since departed from bundled service: Current-Bundled Customers receive the entire compliance value and Later Departing Customers receive none.

The discriminatory-rate determination constitutes action by the Commission beyond its authority and a failure to proceed as required by law under section 1757(a)(1) and (2); or section 1757.1(a)(2)–(3), if section 1757.1 governs.

G. Conclusion of Law 5, Which Finds That Resolving Indifference for One Set of Customers in Isolation from Other Alleged Prior Cost Shifts Would Be Arbitrary, is Erroneous

The Commission finds that retroactively making whole Later Departing Customers "who claim they were made not indifferent under a prior methodology in isolation of other prior

alleged costs shifts" would be arbitrary.[80] This arbitrariness finding, however, is wholly unsupported given the lack of proof of any prior cost shifts, and the fact that any past cost shifts would have fallen equally on all Then-Bundled Customers, which included Later Departing Customers. The Commission adopts the untenable principle that the failure to correct one identified cost shift in violation of statute can be justified by other failures to comply with the law by allowing other cost shifts, which may or may not exist. In addition, failure to resolve a proven present cost shift is an abuse of discretion and is not in accordance with law.

The Commission's arbitrariness finding results in it not proceeding as required by law, is not supported by the findings, the findings are not supported by substantial evidence in light of the whole record, and is an abuse of discretion under section 1757(a)((2)–(5), or section 1757.1(a)(1) and(2), and (4), if section 1757.1 governs.

Each legal error is described in detail below.

V. THE COMMISSION ACTED BEYOND ITS STATUTORY AUTHORITY AND FAILED TO PROCEED IN THE MANNER REQUIRED BY LAW BY FAILING TO COMPLY WITH SECTION 366.2(G)'S REQUIREMENT TO PROVIDE VALUE FOR BENEFITS THAT REMAIN WITH BUNDLED CUSTOMERS

Section 366.2(g) requires the Commission to ensure that "estimated net unavoidable electricity costs paid by [CCA customers] shall be reduced by the value of *any benefits that remain with bundled service customers,* unless the [CCA customers] are *allocated a fair and equitable share of those benefits*."[81] The Commission acted beyond its statutory authority and failed to proceed in the manner required by law and set forth in section 366.2(g) by assigning zero value to Later Departing Customers when the IOUs use Pre-2019 Banked RECs for bundled customer RPS compliance. As set forth below, the Decision: (1) fails to recognize section

[80] Decision at COL 5.
[81] Section 366.2(g) (emphasis added).

366.2(g)'s ongoing requirement to ensure indifference between unbundled and bundled customers in its finding that D.11-12-018 permanently satisfied the indifference mandates for all future scenarios; (2) errs by characterizing the later compliance benefit as duplicative when the historical MPB credit and later compliance benefit account for different benefits to different customers, at different times; and (3) errs in its characterization of CalCCA's arguments as a request to modify D.11-12-018 and D.19-10-001, rather than an application of section 366.2(g) prospectively to a benefit being realized in the present.

A. Section 366.2(g) Requires the Commission to Account for Benefits That Remain with Bundled Customers, and Doing So Is Neither Duplicative Nor Retroactive

The Decision violates section 366.2(g) by treating indifference as a one-time determination rather than an ongoing statutory obligation to account for benefits *that remain with* bundled customers. Banking RECs preserves their compliance value for later use, separating the realization of the benefit from the year the underlying costs are incurred. The Decision states that "the Legislature did not specify how or over what time frame costs must be allocated or benefits remaining with bundled load must be reflected in PCIA rates."[82] Yet it imposes a categorical timing rule: once the Commission assigned a generation-year market value in D.11-12-018, all statutory indifference obligations concerning those RECs were satisfied, even though they remained banked and later provided compliance value to bundled customers.[83] That rule appears nowhere in the statute and reads "any benefits that remain"—language phrased in the *present* tense—out of section 366.2(g).

The Commission is also incorrect: section 366.2 *does* specify the time frame over which costs and benefits must be allocated. Section 366.2(f)(2) establishes that unbundled customers

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82 Decision at FOF 1.

83 *Id*. at FOF 3, COL 1.

must reimburse the utilities for "estimated net unavoidable electricity purchase contract costs," and it contains an express timing clause for that reimbursement. The costs must be reimbursed "for the period commencing with the customer's purchases of electricity from the [CCA], through the expiration of all then existing electricity purchase contracts entered into by the electrical corporation." Section 366.2(g), referring to the reimbursement of "estimated net unavoidable electricity costs" described in (f)(2), provides an off-setting mechanism that reduces the cost reimbursement by the value of the benefits that remain. Section 366.2(g) is inextricably tied to 366.2(f)(2). It thus creates an ongoing obligation—for the Commission to account for benefits—that runs for as long as unbundled customers are paying costs under (f)(2). Nothing in the statute supports the Commission's conclusion that it satisfied its obligations to account for benefits through a past one-time payment.

The Decision finds that the adoption of the cost allocation methodology in D.11-12-018 for RECs in the years the renewable resources were generated achieved indifference.[84] Therefore, according to the Decision, bundled customers satisfied section 366.2(g) by crediting departing load the market value of Pre-2019 Banked RECs in those generation years, which is "all the indifference mandates required."[85] However, that reasoning fails to address whether the methodology accounted for Later Departing Customers' share of the subsequent compliance benefit. Instead, the Decision states that "the Commission was aware, and stakeholders knew or reasonably should have known," that the banked RECs could be used for future compliance.[86] The Decision also states that the Commission "did not confer a right to a deferred benefit on Later Departed Load or recognize this customer group in any way."[87]

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84 *Id*. at COL 1.
85 *Id*. at 30.
86 *Id*. at 31, and FOF 5.
87 *Id*. at 31, and FOF 4.

Regardless of what the Commission did (or did not do) in D.11-12-018, section 366.2(g) *requires* the Commission to value the deferred benefit. To the extent that a methodology fails to account for a benefit remaining with bundled customers, section 366.2(g) requires that the Commission modify that methodology and value it. The Commission has modified the PCIA methodology before, including by adopting a true-up in D.18-10-019[88] and revising the RA benchmark in the Track 1 Decision.[89] The statutory requirement controls the methodology—not the reverse.

The Decision compounds this error by characterizing recognition of the later compliance benefit as requiring bundled customers to "credit the PCIA *again*"[90] and pay an "*additional* cost to use [the RECs]."[91] But this conflates different groups of bundled customers and which costs they paid in the generation year. The generation-year credit did not compensate Later Departing Customers for the benefit at issue here; in fact, the benefit was partially *paid for* by Later Departing Customers. Those customers were still bundled, paid their share of the associated costs when the RECs were generated and banked, and departed before the RECs were used for bundled RPS compliance. They could not have received the historical PCIA credit because they were still bundled customers at the time. Providing their share of the later compliance benefit therefore does not credit any customers "again"; it accounts for a benefit Later Departing Customers paid for but never received.[92] The Decision's concern that recognizing this benefit

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88 D.18-10-019 at COL 1 ("The Commission's current PCIA methodology leads to outcomes that are inconsistent with the requirements of Sections 365.2 and 366.3 . . . and should be revised as specified in this decision.").

89 D.25-06-049 at COL 1 ("The Commission's current RA MPB calculation methodology leads to outcomes that are inconsistent with the requirements of Sections 365.2 and 366.3 and should be revised as described in this decision.").

90 *See* Decision at 3, 43.

91 *See id*. at 10, 28, 29, 34, FOF 9, and COL 3-4.

92 *See supra,* n. 41.

would impose an additional cost on bundled customers also does not resolve the relevant statutory question.[93] A charge reflecting a benefit bundled customers receive is not, merely because it increases their costs, a prohibited cost shift under sections 366.3 and 365.2. To find otherwise would completely undermine the structure of the PCIA and the indifference framework, and would directly conflict with section 366.2(g), which requires the Commission to account for all benefits *remaining with bundled customers.* Whether a corresponding credit is required turns on the fair allocation of that benefit, not solely on whether bundled customers would pay more than under the existing methodology. Under the Decision, bundled customers retain the *entire* later compliance benefit, including the share attributable to Later Departing Customers, without providing those customers a corresponding credit. In effect, Current-Bundled Customers are receiving the Later Departing Customers' share of the compliance benefit *for free.* In this way, the zero valuation for Pre-2019 Banked RECs used for Current-Bundled Customers' present RPS compliance also creates a prohibited cost shift under sections 366.2(a)(4), 366.3, and 365.2, because it causes Later Departing Customers to subsidize Current-Bundled Customers' present RPS compliance, creating a windfall for Current-Bundled Customers. Eliminating that windfall does not create a cost shift—it prevents a cost shift that would otherwise occur when the IOUs use the banked RECs in the present.

The Decision also improperly conflates accounting for a benefit when realized with reopening past rates.[94] CalCCA seeks recognition of the compliance value (and prevention of a cost shift) when the IOUs use the RECs *now*, and does not seek to revise rates charged in the generation years. In fact, the issue only arose when the IOUs began using Pre-2019 Banked

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[93] *See* Decision at 29 ("to require bundled customers to pay an additional cost to use these RECs would violate indifference mandates and would result in unreasonable rates for bundled customers.").

[94] *Id*. at 32.

RECs for bundled customer compliance. The Decision itself applies its treatment to the 2026 true-ups and 2027 forecast rates, confirming that the Commission is determining the rate treatment of these compliance benefits *in those periods*.[95] The Commission cannot establish that CalCCA's proposed treatment is retroactive merely by pointing to when the RECs were generated or their costs incurred. Accounting for the compliance benefit in the period it is realized by bundled customers prospectively applies section 366.2(g) to that use.

B. Neither D.19-10-001 Nor the Working Group Report Resolved Whether Later Departing Customers Must Receive Credit for the Later Compliance Benefit

The Decision separately errs by treating D.19-10-001 and the preceding Working Group Report as having resolved the valuation issue presented in Track 2.[96] It relies on the Report's statement that Pre-2019 Banked RECs "have already been bought and paid for by bundled customer[s] at previous years' RPS Adders," together with the statement that the post-2018 methodology adopted in D.19-10-001 applies only prospectively, to conclude that the RECs were fully allocated and that further recognition of their value would violate indifference.[97]

Neither proposition resolves the question here. The Report's statement concerns the historical treatment of the RECs; it does not determine how to account for the compliance benefit when customers who helped fund those RECs subsequently depart. Indeed, the statement that bundled customers paid for the RECs does not establish that those vintages of customers who later departed surrendered their share of the benefits preserved through banking. Later Departing Customers *were* some of the bundled customers who "bought and paid for" their share of the Pre-2019 Banked RECs, as were Current-Bundled Customers who paid for their share. Bundled

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95 *See id*. at OP 2 (requiring incorporation of the zero valuation into the 2026 true-ups and 2027 forecasted rates).

96 *Id*. at 32-34.

97 *Id*.

customers never pay other bundled customers for RECs at the RPS MPB; the Report was addressing customers who had already departed and already received a credit, to ensure they did not receive a second credit.[98] Likewise, establishing the prospective application of post-2019 Banked RECs does not affirmatively establish that Pre-2019 Banked RECs should receive zero value.

Neither the Working Group Report nor D.19-10-001 addressed whether section 366.2(g) requires recognition of the later benefit. Their silence cannot establish that the Commission previously resolved the issue or fully satisfied the statutory indifference obligation. The Decision therefore cannot rely on those materials to foreclose consideration of the benefit retained for bundled customers when the IOUs use Pre-2019 Banked RECs for RPS compliance on behalf of its bundled customers. The Commission must instead comply with section 366.2(g) and compensate Later Departing Customers with "the value of any benefits that remain with bundled service customers"—i.e., the value of the Pre-2019 Banked RECs to bundled customers when they are used for RPS compliance. A zero-valuation does not comply with that requirement and should be vacated on rehearing.

VI. THE COMMISSION FAILED TO PROCEED IN THE MANNER REQUIRED BY SECTION 1731 AND ABUSED ITS DISCRETION BY FINDING CALCCA'S CLAIMS UNTIMELY

The Decision recasts CalCCA's position from seeking indifference *today* under section 366.2(g) into an allegation of a cost shift and legal error in D.11-12-018 and D.19-10-001.[99] The Decision concludes that CalCCA's claim is untimely because it failed to seek rehearing of those decisions pursuant to section 1731(b)(1).[100] Section 1731(b), however, allows rehearing only of

98 *See* OA Tr. at 223:3-21 and 261:14-262:6.
99 Decision at FOF 10 and COL 6.
100 *Id*. at FOF 15-17 and COL 6.

"matters determined in the action or proceeding." The Commission errs because neither D.11-12-018 nor D.19-10-001 *determined* the indifference treatment applicable when Pre-2019 Banked RECs are later used for bundled customer compliance. The Commission was silent on that issue, and CalCCA and its CCA members could not have sought rehearing of determinations the Commission never made.

The Decision itself even finds that D.11-12-018 did not recognize Later Departing Load as a customer group.[101] However, despite that conclusion, the Decision finds that at the time it adopted D.11-12-018, the Commission "was aware of the bankable nature of RPS compliance instruments" and "omitted credits for customers who were not yet departing load."[102] And, the Decision states that the Commission "did not adopt a framework that required the RECs to be valued again in the year the RECs are used to satisfy bundled customer compliance obligations to impart additional value to Later Depart[ed] Load."[103] First, nowhere in D.11-12-018 does the Commission "omit credits" for Later Departing Load, a group of customers that the Decision acknowledges was not recognized in D.11-12-018. In addition, the Decision finds that because D.11-12-018 *did not adopt* a framework for later value, CalCCA is now seeking redress for customers allegedly "rendered not indifferent under prior methodologies . . . ."[104] However, the absence of a determination is not a determination for which CalCCA is now seeking rehearing.

The Commission's reasoning arbitrarily conflates the absence of a determination with an affirmative determination. The fact that D.11-12-018 did not adopt a mechanism for recognizing the future compliance value of Pre-2019 Banked RECs does not mean it affirmatively

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101 *Id*. at FOF 4. The Joint IOUs also stated at Oral Argument that "[t]he Commission never recognized the category of later departing customers that would be owed additional value if an IOU later used the RECs for compliance." OA Tr. at 230:15-17.

102 Decision at 38.

103 *Id*.

104 *Id*. at 39.

determined that such value must be zero. Decision 11-12-018 did not address what value, if any, should be recognized when these RECs are later used for bundled customer RPS compliance. Nor did D.19-10-001 or the Working Group Report leading up to it make or address that determination, as the Commission and other stakeholders have repeatedly acknowledged.[105] Indeed, the Commission itself apparently concluded that D.11-12-018 and D.19-10-001 had not conclusively determined this issue when it decided to scope this issue for resolution in this proceeding. In addition, what stakeholders at the time the Commission adopted D.11-12-018 "knew or reasonably should have known" regarding banking RECs and using them in the future to satisfy bundled customer RPS compliance is not relevant to section 1731 and what the Commission affirmatively decided.[106] The Decision therefore invents determinations never made and faults CalCCA and its members for failing to challenge them years ago.

Section 1731(b)(1) allows rehearing only with "respect to matters *determined* in the action or proceeding."[107] California Supreme Court and Commission precedent distinguish matters actually determined from issues an earlier decision simply did not address. Where a prior decision includes no meaningful discussion of an issue and resolution of that issue was not necessary to the decision, its silence cannot later be converted into an affirmative determination.[108] The Commission itself has rejected precisely that type of inference, concluding that a prior decision's silence on an issue "can not reasonably be construed to establish

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105 *See infra.,* Section IX.

106 Decision at FOF 7; *see also* OA Tr. at 224:2-8 ("Silence is not a basis for rehearing. The law permits rehearing only on matters determined, that is matters actually decided in the decision. What stakeholders knew or reasonably should have known has no legal effect. If an issue isn't addressed in a decision, you can't seek rehearing on it because the law says the Commission never decided.").

107 Section 1731(b)(1) (emphasis added).

108 *See People v. Gray* (2023) 15 Cal.5th 152 (declining to read an earlier Supreme Court opinion as establishing a requirement where "the question was not before us"); *see also People v. Sims* (1982) 32 Cal.3d 468, 484 ("An issue is actually litigated '[w]hen it is *properly* raised, by the pleadings or otherwise, and is submitted for determination, and is *determine*. . . .").

Commission policy."[109] Indeed, adoption of the Decision's policy would create a dangerous precedent, requiring parties to seek rehearing every time the Commission could have addressed an issue, but didn't.

Neither D.11-12-018 nor D.19-10-001 determined that Later Departing Customers would receive zero value when Pre-2019 Banked RECs are subsequently used for bundled customer RPS compliance. Nor was such a determination necessary to either decision. The fact that D.11-12-018 addressed the value recognized in the year RECs were generated did not require the Commission to determine the treatment of a distinct compliance benefit realized years later. In addition, neither D.19-10-001 nor the Working Group Report addressed how to maintain indifference for Later Departing Customers when those Pre-2019 Banked RECs are subsequently used.[110]

CalCCA and its members' challenge to the current decision was also not ripe prior to the present. Ripeness requires issues that are fit for decision—i.e., that arise from a concrete factual record rather than a controversy that is only hypothetical.[111] Here, the cost shift remained hypothetical until the IOUs began using pre-2019 banked RECs for Current-Bundled Customer compliance and proposing to provide no credit or value to Later Departing Customers in the PCIA. Because the issue was still hypothetical until that time, the parties likewise did not suffer

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109 D.07-12-021 at 20.

110 In fact, SCE petitioned for modification of D.23-06-006, asking the Commission to specify that D.19-10-001's treatment of banked RECs applies only to RECs generated and banked on or after January 1, 2019, and not to Pre-2019 Banked RECs. The Commission denied the petition. It recognized that "parties have different perspectives about the direction in D.19-10-001 and its applicability to pre-2019 RECs," and stated that it did "not have the record to fully evaluate them here" and "may consider the issue in a future rulemaking." *See* D.24-08-004 at 5; *see also id*. at COL 1 ("In D.23-06-006, the Commission did not modify D.19-10-001.").

111 D.18-05-050, *Order Instituting Rulemaking Regarding Whether to Adopt, Amend, or Repeal Regulations Governing the Award of Intervenor Compensation* (May 31, 2018), at 2 (citing *PG&E Corp. v. Pub. Util. Com.* (2004) 118 Cal.App.4th 1174, 1217).

hardship from the Commission withholding consideration of the issue, another element that is required for an issue to be ripe.[112]

CalCCA and its members had no determination on this issue that they could challenge on rehearing of D.11-12-018 or D.19-10-001. Its Track 2 position cannot be deemed untimely for failing to challenge a determination that did not exist. The Decision also cannot arbitrarily supply that determination now and retroactively fault CalCCA for failing to challenge it years earlier. Moreover, CalCCA cannot be penalized for having failed to assert a challenge that was not ripe. The Decision's arbitrary untimeliness conclusion should be rejected.

VII. THE COMMISSION FAILED TO PROCEED IN THE MANNER REQUIRED BY SECTION 1705, FAILED TO SUPPORT ITS DECISION WITH FINDINGS ON ALL MATERIAL ISSUES, AND THE FINDINGS LACK SUBSTANTIAL EVIDENCE SUPPORT

While the Decision contains findings, those findings fail to comply with section 1705's requirement that the findings resolve "issues material to the . . . decision" that zero valuation satisfies section 366.2(g). In other words, the Commission must make findings to support its conclusion that assigning the entire compliance value to Current Bundled Customers while providing zero value to Later Departing Customers for Pre-2019 Banked RECs satisfies the statutory indifference requirements. Section 1705 requires that Commission decisions "contain, separately stated findings of fact and conclusions of law . . . on all issues material to the order or decision." The California Supreme Court has stated that "[e]very issue that must be resolved to reach [an] ultimate finding is 'material to the order or decision.'"[113] The Commission therefore must make the requisite findings upon which that ultimate conclusion rests.[114] Such findings "afford a rational basis for judicial review," allowing a reviewing court to do more than "only

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112 *Ibid.*

113 *California Motor Transp. Co. v. Pub. Utils. Comm'n* (1963) 59 Cal.2d 270, 273.

114 *Id.* (citations omitted).

guess at how" a conclusion was reached.[115] An ultimate conclusion supported only by "bare-bones conclusory findings" is insufficient because the findings must disclose the factual and analytical basis for the Commission's determinations.[116]

The Decision fails to make adequate findings directly addressing the indifference requirements. The Commission does not find that the ongoing indifference requirements of section 366.2(g) have been satisfied for Later Departing Customers and that those customers have received value for the benefits remaining with bundled customers. Neither does the Commission find that Later Departing Customers did not "experience any cost increases as a result of an allocation of costs that were not incurred on behalf of the departing load."[117]

The only related FOF that speaks directly to the cost shift related to Later Departing Customers – rather than the alleged delay in bringing the claim – is as follows:

> FOF 4. . . . The Commission did not recognize "Later Departing Load" as a customer group in D.11-12-018 in any way.
>
> FOF 10. The alleged cost shift CalCCA is attempting to rectify pursuant to . . . section 366.2(g), is, in fact, an allegation of a cost shift under the pre-2019 framework.

The Decision therefore states that the cost shift only occurred pre-2019, and it was implicitly addressed in 2011 and again in 2019, despite failing to recognize Later Departing Customers as a customer group. Neither finding speaks to whether Later Departing Customers are made indifferent under the 366.2(g) standard by receiving no credit for RECs they paid for but did not benefit from, nor do these findings support a conclusion that D.11-12-018 conclusively addressed an issue FOF 4 explicitly states that decision did not consider.

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115 *Id.* at 274 (citations omitted).

116 *Toward Utility Rate Normalization v. Public Utils. Comm'n* (1978) 22 Cal.3d 529, 540; *California Motor,* 59 Cal.2d at 273; *Greyhound Lines, Inc. v. Pub. Utils. Comm'n* (1967) 65 Cal.2d 811, 813.

117 Sections 366.3 and 365.2.

The Decision's COL likewise are insufficient and, again, fail to address Later Departing Customers:

> COL 1. Bundled customers of SDG&E, SCE, and PG&E satisfied the indifference mandates, including section 366.2(g), when bundled customers credited departing load the market value of Pre-2019 Banked RECs in the years they were generated, in compliance with the indifference methodology adopted in D.11-12-018.
>
> COL 4. Because the indifference mandates were satisfied under the pre-2019 methodology, to require current bundled customers to pay an additional cost to use the resources for which costs have already been allocated under the pre-2019 methodology would violate the indifference mandates.

The Decision also fails to determine or explain the amount and incidence of the compliance benefit. It adopts a zero valuation without weighing CalCCA's evidence that the RPS MPB measures the avoided cost associated with current compliance, without making findings on how much of the RECs paid for by Later Departing Customers were used, and without explaining why a valuation or allocation method would duplicate compensation or impose an unreasonable cost on bundled customers. In fact, CalCCA presented valuation and allocation approaches and explained how they avoid duplicate recovery, which were ignored by the Commission.[118] Absent conclusions on the issues called for by the governing statute these are bare bones conclusory findings that are insufficient to support the Decision.

The Decision's characterizations result in a sidestepping of the inquiry necessary to answer the "issues material to the . . . decision": whether unbundled customers, who paid for Pre-2019 Banked RECs when they were bundled but who later departed, are statutorily entitled to receive their share of benefits when the RECs are later used to satisfy the RPS compliance obligations of Current Bundled Customers. The Decision therefore fails to satisfy the requirements of section 1705.

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[118] Ex. CCA-01 at 16:15-20:8.

VIII. THE COMMISSION FAILED TO PROCEED IN THE MANNER REQUIRED BY LAW, FAILED TO SUPPORT ITS ZERO VALUATION DECISION WITH ADEQUATE FINDINGS BASED ON SUBSTANTIAL EVIDENCE, AND ABUSED ITS DISCRETION BY OMITTING ANY CONSIDERATION OF CALCCA'S COST-NEUTRAL ALLOCATION ALTERNATIVE

The Commission violates section 1705's findings requirement and abuses its discretion by failing to consider CalCCA's cost-neutral allocation alternative despite concluding that the Commission cannot value Pre-2019 Banked RECs at anything other than zero on the basis that doing so would purportedly result in "unreasonable rates for bundled customers" and an increase in their costs.[119] CalCCA proposed, in the alternative, allocating Pre-2019 Banked RECs to the LSEs serving later departing customers via a decrement to RPS procurement need.[120] The Decision summarizes CalCCA's proposal but never analyzes it.[121] However, the Decision's dispositive rationale that requiring bundled customers to pay a purported additional cost would be unreasonable and would violate indifference— does not apply because allocation imposes no cost on bundled customers.[122] Section 366.2(g) expressly contemplates allocation of a fair and equitable share of benefits as the alternative to a cost reduction. Failure to make findings on a material, record-supported alternative violates section 1705. Because the Decision likewise fails to provide Later Departing Customers with any value (in credit or in kind) for benefits that remain with Current-Bundled Customers, it also violates section 366.2(g) and represents a failure to proceed in the manner required by law.

The Commission's failure to consider CalCCA's cost-neutral allocation alternative is also an abuse of discretion. Under the abuse of discretion standard, the Commission must adequately

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119 Decision at 29; OA Tr. at 245:23-25 (Commissioner Baker stating at Oral Argument that "we really don't want to impose costs on anyone right now" and "Let's just try to solve this in a way that doesn't cost anybody – any ratepayers any money").

120 Ex. CCA-03 at 22:6-8.

121 Decision at 21-22.

122 *Id*. at 29 and COL 3-4.

consider all relevant factors and demonstrate a rational connection between those factors, the choice made, and the enabling statute.[123] The Commission errs by refusing to consider the merits of alternatives that allow the Commission to fulfill its statutory obligations.[124] Here, the Commission had obligations to both provide value for benefits that remain with bundled customers and to ensure no cost increases relative to what would have occurred had the Later Departing Customers remained bundled customers. The refusal even to evaluate a solution that addresses both obligations and addresses the Commission's principal objection to CalCCA's primary proposal means that the Commission both hasn't adequately considered all relevant factors and has failed to demonstrate the required rational connection between the factors, the decision, and the statute.

IX. THE COMMISSION FAILED TO PROCEED IN THE MANNER REQUIRED BY LAW, FAILED TO SUPPORT ITS DECISION WITH ADEQUATE FINDINGS BASED ON SUBSTANTIAL EVIDENCE, AND ABUSES ITS DISCRETION BECAUSE THE LACHES RULING IS UNSUPPORTED AND CONFLICTS WITH THE RECORD OF AN UNRESOLVED ISSUE

CalCCA and its member CCAs have diligently and consistently pursued the argument that all customers who paid to generate Pre-2019 Banked RECs used for bundled customer compliance must receive their share of the benefits of those RECs. The record in this proceeding and the multiple prior proceedings in which this issue was disputed demonstrate that these arguments were timely, ripe, and appropriate for decision on the policy merits in *this* proceeding.

Nevertheless, the Decision erroneously finds that laches bars CalCCA from raising its claims in this proceeding because CalCCA and its members failed to file for rehearing of D.19-

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123 *Securus Technologies LLC v. Public Utilities Commission* (2023) 88 Cal.App.5th 787, 803.

124 *See City and County of San Francisco v. P.U.C.* (1971) 6 Cal.3d 119, 126-30 ("For failure to consider lawful alternatives ... , the decision of the commission must be annulled."); *City of Los Angeles v. P.U.C.* (1975) 15 Cal.3d 680, 684, 704.

10-001.[125] Laches is an equitable doctrine that prevents a party who has 'slept on their rights' from raising them too late in a way that is unfair to another party.[126] Laches, therefore, requires both "unreasonable delay" and a resulting "prejudice" (or acquiescence).[127] The reasonableness of an alleged delay is a fact-based question that turns on what a party "knew or with reasonable inquiry should have known."[128] Neither unreasonable delay nor prejudice occurred here, resulting in legal error through the Decision's finding that laches bars CalCCA's arguments.

A. Unreasonable Delay Does Not Exist Because D.19-10-001 Did Not Resolve the Question of Pre-2019 Banked REC Value, and Only Recently Did the IOUs Start Predicting the Need to Use Pre-2019 Banked RECs

As a threshold matter, CalCCA's claim regarding Pre-2019 Banked RECs cannot be characterized as unreasonably delayed. CalCCA has challenged the Joint IOUs' proposals to value Pre-2019 Banked RECs at zero in all Commission proceedings in which the question has been at issue, and the issue has never been resolved. For laches to apply, CalCCA must have been on notice that the Commission believed the issue had already been decided. The actions of CalCCA, other parties, and the Commission itself demonstrate it was reasonable to consider this issue unresolved, and that this rulemaking forum is the appropriate forum in which to address this question. None of the Commission's twelve prior decisions addressing this issue suggested that the issue had already been decided. Indeed, the Commission demonstrated that it, too, considered this issue unresolved when it scoped the issue here.

The Commission's statements in ERRA cases demonstrate the reasonableness of CalCCA's position that this question had not been previously addressed and the irrationality of the Commission's sudden reversal. The Commission regularly declines to decide issues that are

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125 Decision at 38 and COL 7.
126 D.15-05-004 at 22.
127 *See Johnson v. City of Loma Linda* (2000) 24 Cal.4th 61, 68; *see also* D.15-02-040 at 7.
128 *See* D.95-02-016 at COL 4-5.

not ripe,[129] and, as explained above in Section VI, CalCCA's present challenge was not ripe until the IOUs began to use Pre-2019 Banked RECs for Current-Bundled Customer compliance and proposed to value the RECs at zero in the PCIA. Further, the Commission routinely declines to decide open policy questions in the ERRA cases.[130] That occurred as recently as December 2025 for these RECs, when the Commission continued its pattern of deciding the Pre-2019 Banked REC question on "interim" or "for this case only" grounds.[131] In PG&E's 2026 ERRA Forecast Decision, for example, the Commission found "that PG&E's proposal [to value Pre-2019 Banked RECs at zero] is reasonable *on an interim basis* while awaiting a more comprehensive decision on use of banked RECs in a rulemaking."[132] That Decision explicitly found that D.19-10-001 "did not conclusively resolve how to value pre-2019 RECs," and adopted PG&E's proposal "on an interim basis for the purpose of this decision" because the question was complicated, the subject of "conflicting understandings" and "appropriate for consideration in a rulemaking."[133]

The Decision also acknowledges but erroneously disregards that the Commission has already granted the identical relief CalCCA is asking for (i.e., valuation of Pre-2019 Banked RECs at the RPS MPB) three times (PG&E's 2023, 2024, and 2025 ERRA Forecast decisions).[134] This conclusion is inconsistent with any finding that CalCCA's claim is stale, abandoned, untimely, or unreasonably delayed. How could the Commission have found that

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129 D.18-11-005 at 4 (citing D.18-05-050 at 3).

130 OIR at 10 ("the [2026 Energy Resource Recovery Account (ERRA)] process itself is intended to function as an individual electric IOU's annual forecast and accounting review, not as a forum for evaluating or setting policy.")

131 D.25-12-028 at 111-113 and COL 14 (treating resolution as "interim"); D.25-12-027 at FOF 15 ("on an interim basis for the purpose of this decision"); D.24-12-039 at 68 (approving treatment "for this proceeding"); D.24-08-004 at 5 (denying SCE's Petition for Modification and saying the Commission "may consider the issue in a future rulemaking"); D.23-11-094 at 60 (treating resolution as "interim").

132 D.25-12-027 at 26 (emphasis added).

133 *Id*. at 31.

134 Decision at 39.

CalCCA's proposal resulted in just and reasonable rates in these three decisions and then now decide that the matter had already been clearly resolved to *prevent* such treatment over a decade ago? The Commission's inconsistent actions and statements again reveal the arbitrary and irrational nature of its decision-making.

Additionally, the Joint IOUs only recently started considering the need to use Pre-2019 Banked RECs. Indeed, it is also clear that parties and the Commission were working together to delay the consideration of the issue to this rulemaking. The Commission even ordered the IOUs to exhaust Post-2018 Banked RECs before turning to Pre-2019 Banked RECs.[135] In every proceeding in which this issue was explicitly raised, CalCCA opposed valuing Pre-2019 Banked RECs at a zero-dollar valuation. Now the issue has finally come to a head. Indeed, the Scoping Memo launching this Track 2 characterized the Pre-2019 Banked REC valuation question as one that had "emerged as exigent."[136] Characterizing CalCCA's position as unreasonably delayed therefore ignores the facts and should be rejected.

The Decision also faults CalCCA for not challenging an IOU's use of banked RECs to satisfy RPS compliance obligations before 2019.[137] The Commission is referencing [redacted]

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135 *See, e.g.*, D.23-11-094 at COL 5-7, OP 9.

136 R.25-02-005, *Amended Scoping Memo* (Feb. 3, 2026), at 2.

137 D.26-09-047 at 23, n.118 ("No party challenged D.11-12-018 for not requiring such a credit, and no party challenged the applicable PCIA rates that did not include the credit CalCCA now claims is required by law on this basis."); FOF 9.

138 Exhibit CCA-[redacted]; section 399.13(a)(5)(B) (ordering the Commission to adopt "Rules permitting retail seller to accumulate, beginning January 1, 2011, excess procurement in one compliance period to be applied to any subsequent compliance period.").

139 *See* OA Tr. at 261:4-9 (discussing the one CCA that existed when D.11-12-018 was issued).

[redacted] Under these circumstances, it is illogical and arbitrary to fault CalCCA or its members for failing to challenge that IOU's proposal and resulting rates.

B. The Decision's Determination of Prejudice Ignores That the Joint IOUs Were on Notice of CalCCA's Arguments and is Unsupported by Record Evidence of Reliance

The Decision also erroneously adopts the Joint IOUs' laches argument by finding prejudice to the IOUs by CalCCA failing to earlier raise its claims. This finding, however, ignores the history of this dispute and prior positions, and relies on unsupported factual claims. First, the Joint IOUs have been aware that CalCCA and its members have considered this a disputed issue for years and have consistently raised their arguments in applications and rulemakings. The Decision claims that CalCCA's alleged delay "prejudiced other stakeholders" because those stakeholders lost their opportunity to "advocate for the redress of other past cost shifts" and because they "made procurement, allocation, and market offer decisions."[140] But the IOUs made their decisions while on notice that CalCCA considered this matter disputed for all the reasons described *supra*. The IOUs – like the CCAs – made procurement, allocation, and market offer decisions under conditions of uncertainty as this issue remained unresolved.

In fact, the Joint IOUs themselves claimed that the valuation of banked RECs was a live issue as recently as 2023. In R.17-06-026 (and after D.19-10-001) the parties responded to an

[140] Decision at 37. In fact, market evidence rebuts the Decision's statements regarding downstream-consequences and the market offer decisions. *See, e.g., id*. at 40-42 and FOF 18. Over the prior 18 months, SCE and SDG&E filed nine advice letters to buy PCC-3 RECs (eight SCE, about 1 million RECs; one SDG&E, 150,000 RECs). A July 29, 2026, SDG&E Advice Letter states that PCC-3 purchases were cheaper than using its REC bank. In other words, the IOUs were already doing these transactions regardless of the uncertainty of the valuation of the RECs. And these transactions had essentially no impact on the market – in fact, prices dropped (PCC-1 from $20 to $11/MWh; PCC-3 prices dropped in 2025 $3 to $2, and in 2026 from $4 to $2.45). OA Tr. at 267:2-269:16. During the Oral Argument, SCE even conceded its PCC-3 purchases constitute ordinary portfolio optimization, not driven by this proceeding. OA Tr. at 269:17-23.

ALJ request for them to identify what issues remained to be addressed. In SCE's Comments in response, it included:

> How the IOUs should account for the use of banked Renewable Energy Credits (RECs) for RPS compliance. Stakeholders have observed that there is no guidance on how the IOU should account for its use of banked RECs for RPS compliance purposes. The underlying issue is to ensure that the value of the those banked RECs is appropriately accounted for in the IOUs' PABA, adopted in this proceeding in 2018, when and if they are used for the IOU's RPS compliance.[141]

At the time, CalCCA agreed, noting that the Commission should address questions related to "the value that will be placed on the RECs, and specific methodologies for tracking excess RECs and whether they have been previously charged to customers."[142] PG&E's Reply Comments also agreed with SCE, stating that SCE's Comments "correctly recognize that there is no guidance on banked REC accounting."[143] The Joint IOUs' claim of laches is therefore itself untimely, and they cannot demonstrate that they were prejudiced by any alleged delay. Laches is an equitable remedy, and a finding of laches is improper when the invoking party's hands are themselves not clean.[144]

Lastly, the application of laches in this instance runs counter to the practice CalCCA reasonably believed the Commission employs in rulemakings: permitting parties to raise legal and policy arguments as to how the Commission can accomplish its statutory and constitutional

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141 *Opening Comments of SCE on ALJ's Ruling Requesting Comments on Supplemental Greenhouse Gas-Free Proposal and Issues in Scope*, R.17-06-026 (Nov. 7, 2022), at 4.

142 *CalCCA's Comments on ALJ's Ruling Requesting Comments on Supplemental Greenhouse Gas-Free Proposal and Issues in Scope*, R.17-06-026 (Nov. 7, 2022), at 15.

143 *Reply Comments of PG&E to Administrative Law Judge's Ruling Requesting Comments On GHG-Free Resources Supplemental Energy Division Staff Proposal and Issues in Scope*, R.17-06-026 (Nov. 7, 2022), at 5.

144 D.15-02-040 at 7 ("Laches is an equitable doctrine, and the party invoking laches must "come with clean hands." (13 Witkin, Summary of Cal. Law (10th ed. 2005) Equity, § 9; *see Precision Instrument Mfg. Co. v. Automotive Maintenance Machinery Co.* (1945) 324 U.S. 806, 814 (unclean hands "closes the doors of a court of equity to the one tainted with inequitableness or bad faith relative to the matter in which he seeks relief")).

obligations prospectively. CalCCA was unable to find any historical instance in which the Commission used laches to reject a party's argument made through testimony and briefing in a rulemaking. The Decision's reliance on laches to reject CalCCA's claims must be rejected as legally erroneous and arbitrary.

X. THE COMMISSION ACTED OUTSIDE OF ITS AUTHORITY AND FAILED TO PROCEED IN THE MANNER REQUIRED BY LAW BY UNREASONABLY DISCRIMINATING AMONG CUSTOMERS UNDER SECTION 453 THROUGH THE ZERO VALUATION OF PRE-2019 BANKED RECS

The Decision also results in legal error through discriminatory rates. Section 453(a) bars a utility from "mak[ing] or grant[ing] any preference or advantage" to any person, or "subject[ing]" any person "to any prejudice or disadvantage," as to "rates, charges, service, facilities, *or in any other respect*."[145] Section 453(c) separately bars "any unreasonable difference" in those same respects "as between classes of service."[146] However, the Decision awards the full RPS compliance benefit of a banked REC to Current-Bundled Customers while assigning zero value to Later Departing Customers who paid for the same REC through generation rates before departing.

The Decision violates section 453 in two ways. *First,* two groups paid the same generation rates for the same Pre-2019 Banked RECs. When an IOU withdraws those RECs for Current-Bundled RPS compliance, the Decision awards the entire compliance value to one group and zero to the other, based solely on the second group's decision to take CCA service. That is an "advantage" to one group, a "prejudice or disadvantage" to the other, and an unreasonable difference in what each pays, and receives, for the same resource.

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145 Section 453(a) (emphasis added).

146 Section 453(c).

Second, the Decision unreasonably treats customers differently depending on when they departed service. Some departed customers paid to generate Pre-2019 Banked RECs that are held in the Joint IOUs' REC bank. Those RECs have exactly the same RPS compliance characteristics as RECs paid to be generated in 2020-2022 by customers who departed later or are still bundled.[147] And yet the Decision unreasonably and unfairly produces disparate treatment for these two groups of customers who paid for RECs that are identically situated from the RPS compliance perspective.

The Commission's violation of section 453 constitutes action outside of its authority and legal error.

XI. THE COMMISSION'S FINDING THAT CORRECTING A PRESENT COST SHIFT WOULD BE ARBITRARY IN LIGHT OF PRIOR ALLEGED COST SHIFTS IS NOT IN ACCORDANCE WITH LAW, CONSTITUTES AN ABUSE OF DISCRETION, AND IS UNSUPPORTED

The arbitrariness ruling is not in accordance with law, is an abuse of discretion, and is unsupported. The Commission claims that "fairness" requires that it not address the present alleged cost shift arising from the bankable nature of RECs because of the existence of "alleged cost shifts from prior PCIA frameworks, *e.g.,* the likely overvaluation of RA resources under the prior RA MPB methodology" which have not been "retroactively undone."[148] It is a perverse kind of fairness that says an error cannot be corrected because other errors may or may not exist. The Decision states that "[i]t would be arbitrary to adopt a rule to retroactively redress one alleged past cost shift in isolation, simply because the bankable nature of RECs ostensibly

[147] *See* CalCCA Opening Brief at 51 (citing Vol. 1 Tr. 54:13-17; 55:4-56:22; 57:6-58:14 (Joint IOU Panel [Brown, Morien, Pulgar])).

[148] Decision at 38-39.

creates the window to do so."[149] However, solving an alleged cost shift that has been properly presented to the Commission is not arbitrary, but rather is required by law.

The Commission may address problems as they are presented to it, even if it does not solve all problems of that type at once.[150] The Commission also has a legal obligation to ensure indifference and prevent cost shifts.[151] Combining these strands, far from it being arbitrary for the Commission to address a single cost shift that has been presented to it, the Commission *must* do so, as long as doing so is not invidiously discriminatory. Here, the unique nature of banked RECs—i.e., the fact that they may be banked for future use[152]—demonstrates that addressing this particular cost shift—and not others alleged, which, are both not supported by a detailed factual record and, unlike the present cost shift, fell equally on all Then-Bundled Customers rather than uniquely burdening Later Departing Customers[153]-—would not have been invidiously discriminatory. Addressing this present cost shift, unlike the others alleged, also would not have required re-opening any past rates. Given such a present cost shift, the Commission is required to act under the indifference statutes. As a result, the Commission's "arbitrariness" justification should be dismissed on rehearing.

XII. CONCLUSION AND REQUESTED RELIEF

The Decision's zero-dollar rule rests on an erroneous reading of section 366.2(g), an untimeliness ruling that treats silence as a prior determination, findings that do not resolve

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149 *Id*. at 39.

150 *See Pacific Bell Wireless, LLC v. Public Utilities Com.* (2006) 140 Cal.App.4th 718, 739 (Solving problems with respect to certain parties but "not others for the same act" is permissible "unless it can be shown the investigating agency purposefully and intentionally singled out the one company for disparate treatment on an invidiously discriminatory basis."); *BullsEye Telecom, Inc. v. Pub. Util. Com.* (2021) 66 Cal.App.5th 301, 328-31.

151 See sections 366.2 (a)(4), 366.2(g), 366.3, 365.2.

152 OA Tr. at 253:1-24.

153 *Id*. at 272:10-273:4.

questions material to the Decision, a laches conclusion inconsistent with the Commission's own treatment of the issue as unresolved, and an arbitrariness finding that mistakes the Commission's obligations. It also discriminates among customer groups in violation of section 453. The Commission should grant rehearing and adopt a method that accounts for the compliance value of Pre-2019 Banked RECs when that value is realized.

CalCCA therefore respectfully requests that the Commission:

1. Grant rehearing of D.26-09-047;
2. Vacate COL 1–8 and OP 1 to the extent they conclude that Pre-2019 Banked RECs must be valued at zero dollars and that the Commission has no duty to account for their later compliance value;
3. Delete or revise FOF 3–5, 8–10, and 12–18 to correct unsupported inferences and make findings on the customer groups, the historical generation-year credit, the later compliance value, and the allocation of that value;
4. Find that D.11-12-018 and D.19-10-001 did not determine the present section 366.2(g) question and that CalCCA's challenge to D.26-09-047 is timely under section 1731;
5. Reject the laches defense because the record does not establish unreasonable delay and acquiescence or specific prejudice caused by CalCCA's conduct;
6. Adopt a valuation of Pre-2019 Banked RECs at the RPS MPB in the year of use, or allocate the RECs and their compliance value to the customer vintages that paid for them; and
7. In the alternative, reopen the record or return the issue for further findings and determination under sections 366.2(g) and 453, with a method that prevents duplicate recovery while allocating the compliance value to the customers who paid for the RECs.

Because the Decision is effective immediately and directs changes affecting current ERRA updates which will impact customer bills beginning in 2027, CalCCA also requests that the Commission suspend implementation of the zero-dollar methodology pending resolution of this AFR, or issue any other interim relief necessary to preserve an effective rehearing. The Commission has discretion to stay its decisions pending determination of an application for

rehearing.[154] At a minimum, the Commission should direct the IOUs to track all Pre-2019 Banked RECs used for Current-Bundled Customer compliance.

Respectfully submitted,

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CALIFORNIA COMMUNITY CHOICE ASSOCIATION

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[154] *See* D.23-11-052, *Order Staying Resolution TL-19145* (Nov. 9, 2023), at 1 (citing section 1735).



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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 2027 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U 39 E).	A. 26-05-007

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING BRIEF

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SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Contested Issues

- The Commission[1] should order PG&E to modify its methodology for calculating the Retained RA from non-storage resources and align that methodology with SCE's interim methodology and the Commission's Slice-of-Day framework for RA compliance.

- The Commission should permit PG&E to apply Unsold RPS volumes towards its Minimum Retained RPS requirement. However, the Commission should expressly limit PG&E's ability to displace the RECs it previously applied towards a prior year's Minimum Retained RPS requirement, and permit PG&E to make changes to its 2025 Minimum Retained RPS entry only to the extent it displaces previously-used banked RECs with expiring Unsold RPS volumes.

- The Commission should revisit the structure of the CCA meet-and-confer process in order to improve the accuracy of load forecasts used for ratemaking purposes. The Commission should undertake this effort in the ongoing PCIA OIR. The current meet-and-confer process, established in 2016, is not designed to account for rapid and uncertain load growth.

Uncontested Issues

- CalCCA supports PG&E's update to its RA valuation methodology for energy-storage resources to conform with the directives in D.26-07-008. However, PG&E should also align its RA valuation methodology for energy-only and long-duration energy storage resources with the same Decision.

- The Commission should permit PG&E to include the electric generation portion of the authorized interim revenue requirement from its 2027 GRC in 2027 rates.

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

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 2027 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U 39 E).	A. 26-05-007

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING BRIEF

Pursuant to Rule 13.11 of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission) and the schedule adopted in the Assigned Commissioner's Scoping Memo and Ruling (Scoping Memo),[2] the California Community Choice Association[3] (CalCCA) hereby submits this Opening Brief regarding the *Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements And Rates Associated with its 2027*

[2] Application (A.) 26-05-007, *Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2027 Energy Resource Recovery Account (ERRA) Generation Non-Bypassable Charges Forecast, and Greenhouse Gas Forecast Revenue Return and Reconciliation, Assigned Commissioner's Scoping Memo and Ruling* at 5 (Aug. 3, 2026) (Scoping Memo).

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

Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U 39 E) (Application).[4]

Pacific Gas and Electric Company's (PG&E) annual ERRA Forecast proceeding sets Power Charge Indifference Adjustment (PCIA) rates for the upcoming year. The PCIA is the mechanism the Commission uses to ensure "indifference" between bundled and departed customers, as required by California law. To achieve that objective, PCIA rates are set at levels that ensure departed customers remain responsible for the costs of PCIA resources previously incurred on their behalf—but only those costs that remain after the Commission accounts for benefits PCIA resources continue to impart to bundled customers. In this manner, the PCIA framework ensures both bundled and unbundled customers benefit from the resources for which they pay. For bundled customers, PG&E uses those resources to serve load and meet compliance obligations. For departed customers, PG&E credits the value of those resources' attributes against the costs departed customers owe to bundled customers. Striking this fine balance is important not only because the law mandates indifference, but also because PCIA rates can form a significant portion of the generation charges that customers pay.

In this ERRA Forecast proceeding, CalCCA examined several issues that impact the PCIA rates customers pay, including the Resource Adequacy (RA) value of PG&E's PCIA resource portfolio; the Renewables Portfolio Standard (RPS) value of that portfolio; and PG&E's sales and peak demand forecasts. This brief discusses several of those issues but focuses on the primary

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

remaining contested issue between PG&E and CalCCA: PG&E's calculation of the Retained RA value of its non-storage PCIA resources.

In last year's ERRA Forecast proceeding, the Commission adopted changes to PG&E's methodology for calculating the RA value of its storage resources. Those changes were motivated by the Commission's transition to a "Slice-of-Day" (SoD) framework for RA compliance,[5] under which load-serving entities (LSEs) must show sufficient capacity to meet 24 separate hourly RA requirements across each month of the year. The Commission directed PG&E to apply Southern California Edison Company's (SCE) interim SoD methodology to storage resources on an interim basis, recognizing that the Commission would eventually issue a "more comprehensive decision on implementation of the SoD methodology."[6] The Commission did not address the valuation of non-storage resources.

PG&E has now implemented SCE's interim SoD methodology for its storage resources, but its valuation of non-storage resources remains out of step with SCE (and with the Commission's transition to a SoD framework for RA compliance). Meanwhile, the Commission has yet to consider or develop a comprehensive set of reforms to the PCIA ratemaking framework to reflect SoD implementation. The Commission should therefore direct PG&E to align with SCE and apply SCE's interim SoD methodology to all resource types, not just to energy storage. This will help ensure PG&E's RA valuation methodology reflects RA resources' actual value under the SoD RA compliance framework.

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[5] Decision (D.) 25-12-027 at 37 (stating: "[w]e agree the Commission's RA regulatory program has changed enough to warrant a response in this expedited proceeding.")

[6] *Id*. at 37-38.

The remaining contested issues in this proceeding involve PG&E's RPS accounting and its data center load forecasting process. With respect to PG&E's RPS accounting, CalCCA supports PG&E's rebuttal proposal to apply Unsold RPS volumes towards its "Minimum Retained RPS requirement", because this would avoid those Unsold volumes expiring. However, one aspect of PG&E's proposal is to displace the RECs it was previously authorized to apply towards its 2025 Minimum Retained RPS requirement. Parties have already examined and litigated PG&E's 2025 Minimum Retained RPS requirement in multiple cases. The Commission should expressly limit PG&E's ability to displace the RECs it previously applied towards a prior year's Minimum Retained RPS requirement, and permit PG&E to make changes for 2025 only to the extent it displaces previously-used banked RECs with expiring Unsold RPS volumes.

With respect to PG&E's data center load forecast, CalCCA presented testimony illustrating the volatility that inaccurate load forecasts can create in the PCIA and observing that the sales forecast meet-and-confer process between PG&E and CCAs was established in an era before rapid load growth. To ensure data center load forecasts are as accurate as possible, and to mitigate PCIA rate volatility, the Commission should revisit the meet-and-confer process in the pending PCIA rulemaking.

Finally, this brief addresses three uncontested issues. First, PG&E has proposed a narrow change to its RA valuation methodology for storage resources to account for a recent Commission directive in the RA rulemaking related to "battery foldback" (D.26-07-008). CalCCA does not object to that change, but PG&E and CalCCA agree that PG&E should implement *all* directives in D.26-07-008, not just the directive related to battery foldback. Second, PG&E and CalCCA agree that PG&E should incorporate into 2027 rates the electric generation portion of any interim revenue requirement the Commission authorizes in PG&E's 2027 General Rate Case (GRC).

Third, PG&E has addressed the PCIA calculation errors CalCCA identified during the discovery process.

I. LEGAL STANDARDS

In light of the significant impact PG&E's Application will have on both departed and bundled customers, the ratemaking proposals in that Application require the Commission's careful consideration under the applicable legal standards. Those legal standards include requirements established by the Public Utilities Code. They also include the requirements established in prior Commission decisions, rules, regulations, and resolutions that create and subsequently modify the regulatory framework for the utilities' annual ERRA Forecast filings.

First, pursuant to Public Utilities Code Section 451:

> All charges demanded or received by any public utility, or by any two or more public utilities, for any product or commodity furnished or to be furnished or any service rendered or to be rendered shall be just and reasonable. Every unjust or unreasonable charge demanded or received for such product or commodity or service is unlawful.[7]

This foundational "just and reasonable" statutory requirement is applicable to all rates and charges, including those that will be established by this ERRA Forecast proceeding. Commission precedent supports cost-causation principles in setting "just and reasonable" rates, whereby customers are responsible for the costs incurred on their behalf.[8] The Public Utilities Code also requires rates to

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[7] Cal. Pub. Util. Code § 451.

[8] D.15-07-001 at 2 (Jul. 13, 2015) (citing *K N Energy, Inc. v. F.E.R.C.*, 968 F.2d 1295, 1300 (D.C. Cir. 1992) ("[I]t has been traditionally required that all approved rates reflect to some degree the costs actually caused by the customer who must pay them."); *Alabama Elec. Co-op., Inc. v. F.E.R.C.*, 684 F.2d 20, 27 (D.C. Cir. 1982) ('[I]t has come to be well established that electrical rates should be based on the costs of providing service to the utility's customers, plus a just and fair return on equity."); *So. Cal. Edison Authorized to Increase Rates for California Intrastate Electric Services*, 75 CPUC 641 (1973) (recognizing the desirability of each group's bearing its fair share of the cost of service, as such share is measured by the cost of service study).

be non-discriminatory. Public utilities are prohibited from establishing "any unreasonable difference as to rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service."[9]

ERRA Forecast proceedings also implicate statutory prohibitions on cost shifts between groups of bundled and unbundled customers, as PG&E emphasizes in its Application.[10] Section 365.2 of the California Public Utilities Code mandates indifference for departed customers, requiring the Commission to "ensure that departing load does not experience any cost increases as a result of an allocation of costs that were not incurred on behalf of the departing load."[11] Under Section 366.2, unbundled customers are responsible solely for "estimated net unavoidable electricity costs" when determining indifference, and those costs must be reduced by the benefits in the IOUs' portfolios that accrue to bundled customers.[12] The Commission effectuates that indifference mandate through PCIA rates, the 2027 levels of which are the focus of this brief.

II. BURDEN OF PROOF

As the ratemaking applicant, PG&E has the burden of proof on all aspects of its Application and must affirmatively establish the justness and reasonableness of each proposal therein.[13] That burden of proof includes a burden of production, which rests with PG&E on all facts material to its Application. The burden of production requires PG&E to present evidence sufficient to establish disputed facts in its favor by a requisite degree of belief, which in ERRA Forecast

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9 Cal. Pub. Util. Code § 453(c).

10 Application at 8-9.

11 Cal. Pub. Util. Code § 365.2.

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

13 D.23-08-027, *Decision Approving Partial Settlement*, A.21-09-008 (Aug. 18, 2023), at 16.

proceedings is a "preponderance of the evidence."[14] The burden of proof also includes a burden of persuasion, which remains with PG&E throughout this proceeding.[15] That means the Commission should not grant the relief PG&E requests unless a preponderance of the record evidence demonstrates PG&E has affirmatively satisfied its burden of proof with respect to that request.

III. STANDARD OF REVIEW

The Commission has previously determined that Section 1757 of the Public Utilities Code applies to ratesetting proceedings[16] such as the instant Application,[17] which means the final decision must be "supported by the findings," and those findings must be "supported by substantial evidence in light of the whole record" to withstand appeal. Therefore, the Commission should not grant the relief in PG&E's Application without substantial evidence to support the rates requested.[18] California courts will overturn Commission decisions that are not supported by substantial evidence.[19] Mere rubber-stamping of uncorroborated, disputed evidence does not meet this standard.[20] The Commission, therefore, must reject the components of PG&E's Application that are not supported by substantial evidence.

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[14] *See, e.g.*, D.18-01-009, A.17-06-005 (Jan. 16, 2018), at 9-10; D.15-07-044, R.11-02-019 (Jul. 27, 2015), at 29 (observing that the Commission has discretion to apply either the preponderance of evidence or clear and convincing standard in a ratesetting proceeding, but noting that the preponderance of evidence is the "default standard to be used unless a more stringent burden is specified by statute or the Courts.")

[15] *Cal. Farm Bureau Fed. V. State Water Resources Control Bd.*, 51 Cal. 4th 421, 436 (2011).

[16] Cal. Pub. Util. Code § 1757; *see, e.g.* D.20-05-027 at 5 (May 8, 2020) ("As an initial matter, SDG&E cites to the wrong statute, because Public Utilities Code section 1757.1 does not set forth the applicable standards for a ratesetting proceeding like this one. Rather, section 1757 provides the appropriate standard and requires a finding as to whether the Commission's findings are not supported by substantial evidence in light of the whole record.").

[17] Scoping Memo at 7.

[18] Cal. Pub. Util. Code § 1757(a)(4). *See, e.g. The Utility Reform Network v. Pub. Util. Comm'n*, 223 Cal. App. 4th 945, 958-59 (Feb. 5, 2014).

[19] *Id*.

[20] *Id*.

IV. BACKGROUND

A. BACKGROUND ON THE PCIA

Community choice aggregator (CCA) customers receive generation services from their local CCA, and receive transmission, distribution, billing, and other services from the incumbent for-profit utility. CCA customers pay CCA-specific generation rates. CCA rates vary and are partially influenced by local mandates to procure and maintain clean electricity portfolios that, in many cases, exceed state requirements for renewable generation. In addition, CCA and other unbundled customers are subject to several non-bypassable charges (NBC), including the PCIA and the Cost Allocation Mechanism (CAM) surcharge, the 2027 levels of which will be determined in this proceeding.

The Commission has an obligation to ensure "indifference," meaning when customers of investor-owned utilities (IOUs) depart from bundled service and receive their electricity from a non-IOU provider, such as a CCA, "those customers remain responsible for costs previously incurred on their behalf by the IOUs."[21] The PCIA is the tool the Commission adopted "intend[ing] to equalize cost sharing" between these two groups of customers.[22]

B. CALCULATION OF THE PCIA REVENUE REQUIREMENT

The PCIA revenue requirement is derived from two sources in each utility's ERRA Forecast case, as demonstrated in Figure 1.[23] The first is the Indifference Amount forecasted for the year *for which* rates are being set, *i.e.*, the Indifference Amount forecasted for 2027 in the

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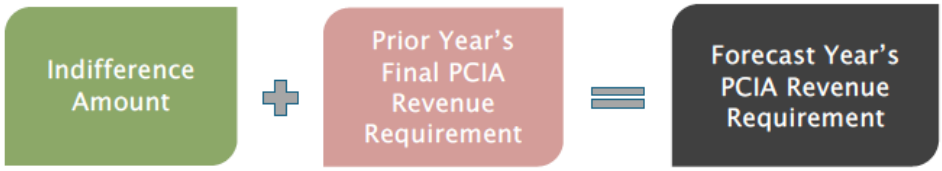
[21] D.24-12-038, *Decision Approving Pacific Gas and Electric Company's 2025 Energy Resource Recovery Account Related Forecast Revenue Requirement and 2025 Electric Sales Forecast*, A.24-05-009 (Dec. 20, 2024).

[22] *See* D.18-10-019 at 3.

[23] Exh. CalCCA-01C at 5.

instant proceeding.[24] The second is the final PCIA revenue requirement for the year *in which* rates are being set, *i.e.*, the final 2026 PCIA revenue requirement in the instant proceeding, which is derived from the balance in the Portfolio Allocation Balancing Account (PABA) the utility anticipates seeing at the end of the year.[25]

FIGURE 1



The Indifference Amount is the difference between the forecasted cost of the IOU's supply portfolio and the forecasted market value of the IOU's supply portfolio as demonstrated in Figure 2 below.[26]

FIGURE 2



Total Utility Portfolio Cost includes:

(i) the cost for Utility-Owned Generation (UOG) (*i.e.*, the capital investment recovery and fixed maintenance costs the Commission sets in a GRC);

(ii) purchased power such as that from power purchase agreements (PPAs);

(iii) fuel costs for UOG and PPAs with tolling agreements, and;

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24 *Id.*

25 *Id.*

26 *Id.*

(iv) California Independent System Operator (CAISO) grid charges and revenues, net of any sales.[27]

The forecasted Portfolio Market Value is derived from total eligible resource output multiplied by the Market Price Benchmarks (MPBs), an administratively determined set of proxy values that estimate the market value of the IOU's resource portfolio.[28] Portfolio Market Value consists of three principal components: Energy Value, RPS Value, and RA Value.

- Energy Value is the estimated financial value, measured in dollars, that is attributed to the generation component of a utility portfolio for a given year.[29]
- RPS Value is the estimated financial value, measured in dollars, that is attributed to the renewable energy component of a utility portfolio for a given year above and beyond the Energy Value.[30]
- RA Value is the estimated financial value, measured in dollars, that is attributed to the resource adequacy component of a utility portfolio for a given year.[31]

MPBs are estimates of the value per unit (not total portfolio value) associated with the three principal sources of value in utility portfolios (non-RPS energy, RPS, and RA capacity).[32] Each

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27 D.11-12-018, *Decision Adopting Direct Access Reforms*, R.07-05-025 (Dec. 1, 2011), at 8-9.

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

29 *Id.*

30 *Id.*

31 *Id.*

32 *Id*.

MPB must be multiplied by the relevant portfolio volume as part of the overall calculation of Portfolio Market Value:[33]

- Energy Index is the MPB that reflects the estimated market value of each unit of energy in a utility portfolio, in dollar value per megawatt hour ($/MWh). It is sometimes referred to as "Brown Power Index," "Brown Power component," "Brown Power Adder," or "Brown Power benchmark."[34]
- RPS Adder is the MPB that reflects the estimated incremental value of each unit of RPS-eligible energy in $/MWh.[35]
- RA Adder is the MPB that reflects the estimated value of each unit of capacity in a utility portfolio that can be used to satisfy Resource Adequacy obligations, in dollar value per kilowatt ($/kW-month).

The forecast utility portfolio value calculation is shown in Figure 3 below. [36]

FIGURE 3



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33 *Id.*

34 *Id.* at 7.

35 *Id.*

36 Exh. CalCCA-01C at 7.

The forward-looking, forecasted ingredients of total portfolio cost and value are netted against Utility Portfolio Costs to produce the Indifference Amount portion of the PCIA revenue requirement.[37]

The second portion of the PCIA revenue requirement is the "true up." The "true up" modifies the forecasted PCIA revenue requirement from the prior year to reflect, among other things, actual revenues received for products sold from the portfolio and to reflect a zero-dollar value for products left unsold from the portfolio.[38] The revenue requirement modification also updates the proxy market values for products the utilities used to serve bundled customers, changing the *forecast* energy, RPS, and RA MPBs to *final* energy, RPS, and RA MPBs.[39] This "true up" relies on the same methodology used for the forecast and determines the final portfolio value, as shown in Figure 4 below:[40]

FIGURE 4



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37 *Id*.

38 *Id*. at 8.

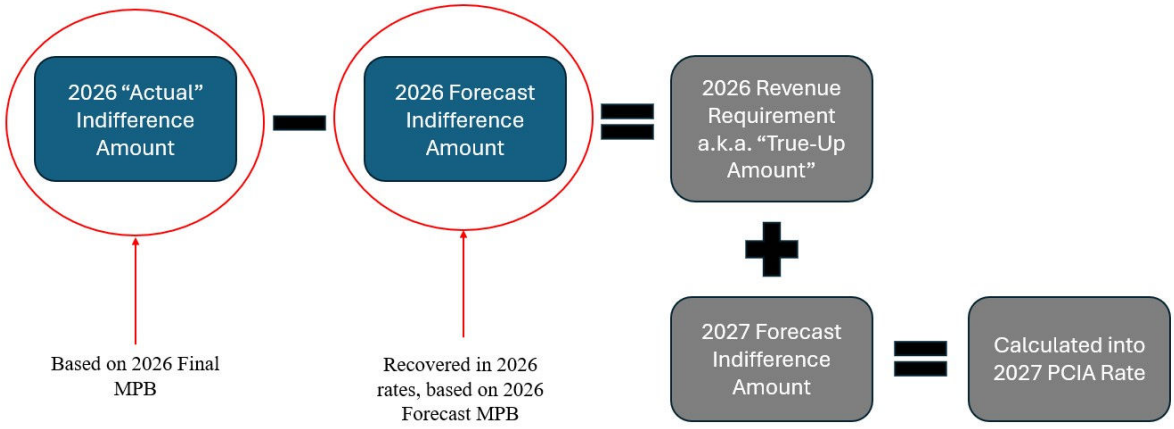
39 *Id*.

40 Because the true-up for 2026 occurs during 2026, this true-up is developed using (1) actual values that are available to date and (2) a forecast of actual values for the remainder of the year. PG&E's Application includes an estimate of the 2026 year-end PABA balance comprising a combination of actual entries from January through March 2026 and a projection of activity from April through December 2026. PG&E's October Update includes an estimate of the 2026 year-end PABA balance comprising a combination of actual entries from January through August 2026 and a projection of activity from September through December 2026. The final December 31, 2026, advice letter implementing the proceeding will include actual entries. *See id*. at 7, fn. 13.

Prior to D.18-10-019, the PCIA rate was set only on a forecast basis with no after-the-fact adjustment to the forecasted PCIA revenue requirement for unbundled customers.[41] Decision 18-10-019 approved such an adjustment via the PABA, a rolling balancing account tracking the difference between costs and revenues used to determine the forecasted PCIA revenue requirement and the actual costs and revenues PG&E realizes during the year related to its PCIA-eligible resource portfolio.[42]

PG&E calculates this final 2026 portfolio value, uses it as an input to the actual 2026 indifference amount, and finalizes the 2026 revenue requirement in this case, as shown below in Figure 5.[43]

FIGURE 5



To summarize, PG&E's PCIA rates for 2027 will be set in this proceeding based on these two components: (1) the forecasted Indifference Amount, *i.e.*, the difference between the forecasted cost of PG&E's generation portfolio in 2027 and the forecasted market value of PG&E's generation portfolio in 2026; and (2) the final 2026 PCIA revenue requirement based on the year-end balance

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41 *Id.* at 8.

42 *Id.*

43 *Id.* at 9.

in the PABA.[44] The Indifference Amount and the final 2026 PCIA revenue requirement are added together to form the 2027 PCIA revenue requirement recovered through rates from bundled and unbundled customers.[45] Finally, per D.22-01-023, the year-end ERRA Balance is transferred to the most recent PABA vintage, and is paid by both bundled and departing load customers that depart on or after July 1 of the preceding year.[46]

C. CUSTOMER VINTAGING AND ALLOCATION

Each generation resource and customer is assigned a "vintage."[47] A distinct portfolio of generation resources is identified for each vintage year based on when a commitment to procure each resource was made.[48] Customers are assigned to vintage years according to the date the customer departed bundled IOU service.[49] Customers continuing to receive bundled service from the IOU are included in the latest vintage (e.g., vintage 2027 in the current application).[50] Each vintage is assigned both a separate Indifference Amount and a separate final 2026 revenue requirement[51] and customers are responsible for the cumulative Indifference Amount for years prior to and including their vintage.[52] The PCIA revenue requirement is allocated among both

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44 *Id*.

45 *Id*.

46 D.22-01-023 at Ordering Paragraph (OP) 4.

47 Exh. CalCCA-01C at 9.

48 *Id*.

49 Unlike portfolio resources, customers are assigned to vintages using a July to June calendar period. For example, customers departing bundled service between July 2019 and June 2020 are assigned to the 2019 vintage. *See id*. at 10, fn. 16.

50 *Id*. at 10.

51 D.11-12-018 at 9.

52 Exh. CalCCA-01C at 10.

bundled and unbundled customers based on their vintage and their rate class using the allocation factors from PG&E's most recently approved GRC.[53]

V. CONTESTED ISSUES

A. THE COMMISSION SHOULD DIRECT PG&E TO ADOPT SCE'S INTERIM METHODOLOGY FOR ALL RESOURCE TYPES BECAUSE SCE'S METHODOLOGY REFLECTS THE COMMISSION'S TRANSITION TO A SLICE-OF-DAY FRAMEWORK

1. The Methodology Used To Determine RA Quantity Directly Impacts PCIA Rates.

As discussed above, a key component in PG&E's calculation of the value of its PCIA-eligible resources—which in turn drives the Indifference Amount recovered from bundled and unbundled customers through the PCIA—is the RA value of those resources.[54] PG&E calculates the RA value of its PCIA-eligible portfolio by multiplying the total RA quantity associated with that portfolio (in megawatts (MW)) by the RA MPB (in $ per kilowatt (kW)-month).[55] The RA MPB is an administratively-set proxy value provided each October by Energy Division and cannot be modified in this proceeding. The quantity term used to calculate the RA value of PG&E's portfolio, however, is a contested issue in this proceeding.

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53 D.18-10-019 at 122 and OP 4; Exh. CalCCA-01C at 10.

54 Exh. CalCCA-01C at 10.

55 *Id*.

2. The Commission Has Approved Changes to the IOUs' Methodologies for Determining RA Quantity In Order to Reflect the RA Program's Transition to the SoD Framework.

In recent years, the Commission's transition to a SoD framework[56] for RA compliance has impacted the quantity term used to calculate the RA value of the IOUs' PCIA portfolios in ERRA Forecast cases.

The SoD framework requires LSEs to show sufficient capacity to meet 24 separate hourly RA requirements across each month of the year.[57] From the perspective of an RA resource, the SoD framework considers the capacity contribution of that resource during each hour of the "worst day" of each month.[58] Prior to the Commission's implementation of the SoD framework, the Commission required LSEs to demonstrate compliance with RA program requirements based on the Net Qualifying Capacity (NQC) associated with their RA resources—a measure of each resource's capacity contribution in the single peak hour of each month.[59] The SoD framework is a marked transition away from the previous, NQC-centric approach to RA compliance.

The Commission has not issued any decision or guidance requiring LSEs to reflect the SoD RA compliance framework in PCIA ratemaking. Nevertheless, in recent ERRA cases, the IOUs have proposed certain changes to RA valuation for PCIA purposes to reflect the RA program's transition away from NQC-based compliance. In approving changes to the IOUs' RA valuation methodologies, the Commission has expressly characterized those changes as "interim" solutions,

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[56] The Commission adopted the "Slice-of-Day" framework through the 2021 RA program rulemaking, D.22-06-050 at 120-122, Findings of Fact 10-21, and it became effective in 2025. D.23-04-010, *Decision on Phase 2 of the Resource Adequacy Reform Track*, R.21-10-002 (Apr. 6, 2023), at 73.

[57] Exh. CalCCA-01C at 11.

[58] *Id*.

[59] *Id*.

and acknowledged the Commission intends to comprehensively address the impacts of the SoD framework on PCIA ratemaking in a rulemaking.

SCE was the first IOU to propose changes to its RA valuation methodology for PCIA ratemaking purposes to reflect the SoD framework. In its 2025 ERRA Forecast Case, A.24-05-007, SCE proposed an "interim slice of day methodology" that would "align the RA quantity calculation to account for CPUC-adopted changes in how RA resources are counted for compliance purposes."[60] Specifically, SCE's interim SoD methodology would determine RA capacity based upon the NQC of baseload resources,[61] the average of all 24 hours of SoD capacity for intermittent resources, and for storage resources—NQC minus an estimate of the RA capacity needed for charging.[62] CalCCA contested SCE's methodology for failing to comprehensively address the impact of SoD on RA quantity *and* price, among other things.[63] The Commission, however, found SCE's interim SoD methodology to be a "reasonable execution of guidance given to account for how [RA] is counted for compliance purposes" and approved SCE's application of that methodology on an interim basis.[64] The Commission again approved SCE's interim SoD methodology in SCE's 2026 ERRA Forecast proceeding, A.25-05-008, reiterating its finding from

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60 D.24-12-039, *Decision Approving Southern California Edison Company's 2025 Energy Resource Recovery Account-Related Forecast Revenue* Requirement, A.24-05-007 (Dec. 23, 2024), at 70.

61 The RA value of baseload resources does not change under a SoD framework because those resources contribute the same or near the same RA value (NQC) across all 24 hours of the day.

62 Exh. CalCCA-01C at 13; Attachment RAM-4.

63 D.24-12-039 at 70-71.

64 *Id*. at 75.

the prior year's ERRA Forecast proceeding.[65] This year, SCE again proposes to apply the same methodology for the purposes of 2027 ratemaking.[66]

PG&E proposed changes to its RA valuation methodology to reflect the SoD compliance framework in its 2026 ERRA Forecast proceeding.[67] In that case, PG&E initially proposed to calculate the monthly RA contribution of each resource in its PCIA portfolio based on the weighted hourly average of each of the 24 hours in the SoD capacity calculation.[68] CalCCA objected to PG&E's proposal because of its treatment of storage resources. PG&E's proposal to average storage RA capacity across all 24 hours, including the hours in which storage is charged, did not accurately value the capacity contribution of storage resources because it resulted in a near-zero RA quantity for storage, among other things.[69] CalCCA recommended the Commission address SoD implementation for PCIA ratemaking purposes in a rulemaking, so that the issue could be addressed holistically, including any impacts on both the price and quantity terms used to assess the RA value of PG&E's portfolio.[70] CalCCA recommended in the alternative that the Commission adopt SCE's interim SoD methodology, because that methodology more closely

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65 D.25-12-028, *Decision Approving Southern California Edison Company's 2026 Energy Resource Recovery Account-Related Forecast Revenue Requirement*, A.25-05-008 (Dec. 18, 2025), at 119.

66 *See* SCE Prepared Testimony, A.26-05-006, Exhibit No. SCE-01 at 136-140.

67 A.25-05-011, *Application of Pacific Gas and Electric Company for adoption of Electric Revenue Requirements and Rates Associated with its 2026 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation*.

68 Exh. CalCCA-01C at 12.

69 *Id*. at 13.

70 *Id*.

aligns with the SoD framework and produces results that more closely comport with market realities.[71]

In its Rebuttal Testimony, PG&E proposed certain changes to its SoD methodology to address CalCCA's observation that its original proposal resulted in an unreasonable near-zero RA value for energy storage resources.[72] PG&E proposed to change its weighting approach to apply a 100 percent weighting to the peak load hour in each month and weight the other 23 hours at zero percent.[73] PG&E, however, applied this change to its SoD methodology across all resources (baseload, intermittent, and storage).[74] PG&E's revised SoD proposal did not resolve CalCCA's concerns, nor did it reflect SCE's interim SoD methodology for baseload, intermittent, or storage resources.[75]

Ultimately, in its Final Decision, the Commission determined it was reasonable for PG&E to implement the SoD framework in the 2026 ERRA Forecast, but also agreed with CalCCA's position on energy storage.[76] The Commission found neither of PG&E's proposed SoD RA methodologies (original or revised) to be reasonable, and instead ordered PG&E to "adopt the SCE SoD methodology on an interim basis while awaiting a more comprehensive decision on the implementation of the SoD methodology."[77]

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71 *Id*.

72 *Id*.

73 *Id*.

74 *Id*.

75 *Id*.

76 D.25-12-027, *Decision Approving Pacific Gas and Electric Company's 2026 Energy Resource Recovery Account Related Forecast Revenue Requirement and 2026 Electric Sales Forecast*, A.25-05-011; A.25-09-015 (Dec. 18, 2025), at 37.

77 *Id*. at 37-38.

3. The Commission's Decision in PG&E's 2026 ERRA Forecast Case Resolved RA Valuation for Energy Storage Resources, But PG&E's Methodology for Valuing the RA of Non-Storage Resources Remains Misaligned with the SoD Framework

The Commission's decision in PG&E's 2026 ERRA Forecast case was specific to PG&E's SoD methodology for energy storage resources. The Commission stated:

> PG&E did not provide sufficient evidence that the original and revised proposals would reasonably discount the RA value of *storage resources* by conflating energy with capacity and failing to account for batteries' ability to provide capacity in any hour.[78]
>
> SCE's methodology is simply a method to discount the NQC of *storage resources* to account for the fact that *storage* is not available at its NQC value for 24 hours. PG&E has sufficient information to apply SCE's current methodology for calculating the RA sales; PG&E would apply SCE's current methodology for calculating the RA sales, unsold and retained RA volumes *for storage resources*.[79]

PG&E also understood the Commission's order to refer only to storage resources. In the Advice Letter[80] describing its implementation of the Commission's order into the 2026 PCIA rates, PG&E stated: "Ultimately, in D.25-12-027 the Commission found it was reasonable for PG&E to adopt Southern California Edison's ("SCE's") interim SoD methodology for storage resources only on an interim basis."[81] PG&E further acknowledged that its SoD implementation for the remaining non-storage resource reflected the prior NQC approach when it stated "For all non-storage resources, the NQC values were based on currently approved NQC counting rules."[82]

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78 *Id*. at 37 (emphasis added).

79 *Id*. at 38 (emphasis added).

80 Advice 7820-E, *Notification of PG&E's Implementation of its Slice-of-Day Methodology in Compliance with Decision 25-12-027* (Jan. 22, 2026).

81 *Id*.

82 *Id*. at 1.

Nothing in D.25-12-027 addresses or approves PG&E's approach to SoD implementation for the purposes of valuing RA capacity from non-storage resources. Despite twice approving SCE's interim SoD methodology for all resource types, the Commission has not yet addressed the implementation of the SoD framework for PG&E's non-storage resources. Nor has the Commission yet comprehensively addressed SoD implementation for PCIA ratemaking purposes in a rulemaking. Therefore, it is appropriate for the Commission to address the RA valuation of PG&E's non-storage resources in this case and ensure the quantity term used to determine the RA value of those resources appropriately reflects the Commission's transition to a SoD framework for RA compliance (until such time as the Commission holistically addresses the SoD framework's impact on PCIA ratemaking in a rulemaking).

4. Whereas SCE's Interim SoD Methodology Reflects the Evolution of the RA Program, PG&E's Approach Undercuts It

Unlike SCE, PG&E continues to assess the RA value of intermittent resources based on the resource's peak hour contribution, despite the Commission's transition away from focusing on peak hour NQC in the context of RA compliance.[83] PG&E's methodology is not reasonable, and the Commission should reject it, for two reasons.

First, PG&E's approach leads to a needlessly inconsistent outcome. Under the status quo,[84] the exact same wind and solar resources would be assigned different quantities of retained RA capacity for PCIA ratemaking purposes depending on whether they were procured by PG&E or SCE.[85] Those different retained RA quantities would each be multiplied by the same statewide RA

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[83] Exh. CalCCA-01C at 15; PG&E-01 at 5-12, lines 3-13.

[84] A.26-05-006, SCE Opening Testimony, at 137-139, included as Attachment RAM-4 to Exh. CalCCA-01C.

[85] Exh. CalCCA-01C at 16.

MPB value, resulting in different retained RA values.[86] SCE and PG&E customers receiving a different retained RA value for the same resources solely because they are customers of a different utility would clearly be an inequitable outcome.[87]

Second, PG&E's approach undercuts the Commission's transition to a SoD framework for RA compliance. Again, PG&E's RA valuation methodology uses each resource's output in the single peak hour per month to determine that resource's capacity contribution and the quantity used to value Retained RA in the PCIA.[88] This approach is nearly identical to the NQC-based approach that the SoD framework replaced.[89] That NQC-based approach measured capacity in the single peak hour of each month.[90] PG&E's RA valuation methodology, therefore, effectively circumvents the Commission's effort to evolve the RA program towards considering all hours in the day to ensure resource adequacy.[91] In contrast, SCE's interim SoD methodology—which CalCCA supports—determines the RA quantity associated with intermittent resources by averaging the capacity contribution ("exceedance values") of those resources across all 24 hours in the worst day of the month. In this manner, SCE's interim SoD methodology reflects the RA program's transition to a compliance framework that considers each resource's RA contribution not only during the peak hour, but also during each of the other 23 hours of the day.

The Commission can easily remedy the inconsistency between PG&E and SCE and ensure PG&E's RA valuation methodology better reflects the SoD framework by requiring that PG&E

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86 *Id*.

87 *Id*.

88 *Id*. at 17.

89 *Id*. at 18.

90 *Id*.

91 *Id*.

apply SCE's interim SoD methodology to not only storage, but all resources in its portfolio. To fully align PG&E and SCE's SoD calculations, PG&E should determine the RA contribution of a non-storage intermittent resource by averaging its capacity contribution equally across all 24 hours in the worst day (i.e. day that contains the hour with the highest coincident peak load forecast).[92] Notably, this approach is nearly identical to the one PG&E originally proposed in its initial filing in the 2026 ERRA Forecast case.[93]

5. PG&E's Opposition to SCE's Interim SoD Methodology is Baseless and Misleading

PG&E opposes the application of SCE's interim SoD methodology[94] to non-storage intermittent resources, despite initially proposing a similar methodology in its 2026 ERRA Forecast case. It asserts the Commission's decision in last year's ERRA Forecast case "addressed the interim retained SoD RA methodology for PG&E by explicitly only modifying the treatment of energy storage resources while leaving all remaining elements unmodified, including non-energy storage intermittent resources[.]"[95]

PG&E is correct that D.25-12-027 only modified PG&E's RA valuation methodology for storage resources, but nothing in that Decision expressly addresses PG&E's RA valuation of non-storage resources. In fact, in its reply comments on the Proposed Decision in last year's ERRA Forecast proceeding, PG&E argued that proceeding lacked the record necessary for the

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92 *Id*. at 17.

93 *Id*. at 17, footnote 41 (explaining the only difference is the weighting of the hours. PG&E originally proposed in its 2026 ERRA forecast case to weight the hours by load ratio share, while SCE's methodology provides equal weight to all the hours).

94 PG&E's Rebuttal Testimony references CalCCA's proposed RA valuation methodology, but in response to discovery PG&E concedes CalCCA's methodology is consistent with SCE's interim SoD methodology. Exh. CalCCA-03 (PG&E response to CalCCA DR 10.10).

95 Exh. PG&E-04 at 3-1.

Commission to address the RA valuation of non-storage resources. PG&E stated: "there is no record supporting adoption of SCE's SOD methodology for resources other than energy storage resources nor is there sufficient record for how PG&E would fully calculate retained volumes for any changes beyond energy storage resources . . . Limiting the application of the SCE SOD methodology is the correct outcome as Commission decisions must be based on the record."[96] Those comments—and the language of D.25-12-027 itself—undermine PG&E's suggestion that the Commission "explicitly" addressed the valuation of non-storage RA resources in last year's ERRA Forecast proceeding. Importantly, this year, the record indisputably includes the detail necessary for the Commission to adopt SCE's interim SoD methodology for non-storage resources.

PG&E also asserts SCE's interim SoD methodology would result in "an unjustifiable cost shift to the detriment of PG&E's bundled customers" because that methodology would increase the quantity of RA retained at the MPB. In support of that argument, PG&E presents a convoluted analysis purporting to show that SCE's approach would result in a $224.68 per kW NQC-year "effective MPB" for solar resources, because—according to PG&E—that approach implies "approximately 1.62 MW of retained solar quantity for each MW of peak-hour NQC."[97] PG&E's claims of a cost shift are baseless, and its "effective MPB" analysis is misleading for several reasons.

First, nothing in the record demonstrates the application of SCE's interim SoD methodology would result in an "unjustifiable cost shift" to PG&E's bundled customers. PG&E's allegations of a cost shift rest entirely on the fact that—as CalCCA witness Matley explained—

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[96] A.25-05-011/A.25-09-015 (cons.), *Pacific Gas and Electric Company's (U 39 E) Reply to Opening Comments on the Proposed Decision* at 2-3 (Dec. 4, 2025).

[97] Exh. PG&E-04 at 3-6; 3-7.

the application of SCE's interim SoD method to PG&E's RA portfolio would result in an increase in retained solar RA capacity in 2027.[98] But the mere fact that the application of SCE's interim SoD method would result in an increase in retained solar RA in 2027 does not demonstrate an impermissible "cost shift". The Commission must approve PCIA rates that appropriately reflect the RA value of PG&E's PCIA resources, even if doing so increases the quantity of retained RA.

Second, PG&E's focus on the impact of SCE's interim SoD method on solar RA in 2027 misses the broader implications of that method. PG&E glosses over the fact that the application of SCE's interim SoD method would also result in a decrease in retained wind RA capacity in 2027.[99] More importantly, the results (retained RA capacity) of SCE's interim SoD methodology depend on the average RA contribution of intermittent resources across the 24 hours of the "worst day" of each month. That means SCE's methodology would not necessarily produce an increase in retained Solar RA capacity in every instance (relative to a peak-hour NQC-based method). Further, SCE's methodology would certainly not always result in a ratio of 1.62 MW of retained solar RA for each MW of peak-hour NQC—PG&E derived that ratio entirely from the impact of SCE's method on retained solar RA in 2027.[100] PG&E's assertion that SCE's interim method would produce an effective solar RA MPB of $224.68 per kW NQC is therefore misleading.

Third, PG&E's criticism of SCE's interim SoD method, and its "effective MPB" analysis, is premised on its assertion that the RA MPB is composed primarily of baseload RA transactions, and is therefore effectively a baseload price.[101] According to PG&E, in the PCIA, both solar RA

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98 *Id*. at 3-6 to 3-7.

99 Exh. CalCCA-01C at 17.

100 Exh. CalCCA-07 (PG&E response to CalCCA DR 11.02).

101 Exh. PG&E-04 at 3-5.

and baseload RA get a baseload price (the RA MPB) despite actual market transaction data showing a disparity between the prices each resource type receives,[102] leading to the overstatement of solar RA value under SCE's interim SoD methodology (and even under PG&E's current methodology). But PG&E's assumption is unfounded. PG&E concedes it does not have insight into the full set of RA market transaction data that determines the MPB—its assertion is based solely on its review of Central Procurement Entity transactions.[103] Assuming the RA MPB reflects RA transactions from multiple technology types, it necessarily undervalues baseload resources and overvalues lower-priced resources. Only the Commission is aware of the full set of RA market transaction data that goes into the RA MPB, and therefore the record of this proceeding does not and cannot establish the extent to which the MPB undervalues baseload or overvalues lower-priced resources.

Fourth and finally, PG&E's "Effective MPB" analysis is mathematically unsound. Although PG&E claims its RA valuation methodology is based on the NQC of each Resource, it is in fact based on each resource's peak hour RA contribution. That number diverges significantly from CAISO-published NQC values in several instances.[104] This mismatch undermines PG&E's argument that its methodology aligns with the manner in which the RA MPB is expressed (i.e., a price per kW NQC).

PG&E's "Effective MPB" analysis is ultimately a distraction. The RA MPB is calculated by Energy Division and no party has insight into the full set of RA market transactions informing

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102 *Id*. at 3-7.

103 Exh. CalCCA-02 (PG&E response to CalCCA DR 10.04).

104 *See* Exh. CalCCA-04 and CalCCA-05 (PG&E response to CalCCA DR 10.14, and accompanying attachment).

that price. The RA MPB is not differentiated by technology. Nothing about the RA MPB will change in this proceeding. The only dispute is over the quantity term that must be multiplied by the RA MPB to determine the RA value of PG&E's non-storage resources. The Commission must determine whether using the resource's peak hour RA contribution—per PG&E's proposal—or average contribution over 24 hours—per SCE's interim SoD method, better reflects the RA resource's value in a SoD 24-hour compliance framework. PG&E asserts that RA market prices, and the RA MPB, "continue to be expressed in terms of NQC",[105] but PG&E misses the point. Under the SoD framework, the value of an RA resource, including a solar RA resource, is its contribution towards RA requirements in all 24 hours of the day, across all 12 months of the year. That value is misaligned with the solar resource's peak hour contribution. For instance, during winter months, the Commission's Master Resource Data file reports an NQC near 0 MW for solar RA resources[106] and a buyer would pay for solar RA based on the peak hour NQC volume purchased.[107] But the value of that solar RA, under the SoD framework, would not be zero even in winter months; rather, it would be driven by the resource's contribution across 24 hours. PG&E's focus on the terms in which RA market prices are expressed misses the Commission's transition to a 24-hour RA compliance framework, and the impact of that transition on RA value.

The Commission should therefore adopt SCE's interim SoD method for PG&E's non-storage resources. While CalCCA supports the Commission's holistic evaluation of SoD implementation in the PCIA context in Track 4 of the PCIA rulemaking,[108] the Commission should

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105 Exh. PG&E-04 at 3-6.

106 Exh. CalCCA-06C (PG&E response to CalCCA DR 10.16).

107 Exh. CalCCA-08 (PG&E response to CalCCA DR 11.06).

108 Exh. PG&E-04 at 3-8.

establish an interim approach for PG&E that aligns with SCE and better reflects the SoD framework until the holistic evaluation is complete.

B. WHILE THE COMMISSION SHOULD APPROVE PG&E'S PROPOSAL TO RETAIN AND VALUE UNSOLD RPS VOLUMES, IT SHOULD EXPRESSLY LIMIT PG&E'S ABILITY TO DISPLACE THE RECS APPLIED TOWARDS MINIMUM RETAINED RPS ENTRIES IN PRIOR YEARS

1. Renewable Energy Credits are a Crucial Component of PG&E's Portfolio Value

As mentioned above, a major component of PG&E's overall PCIA portfolio value is its "RPS value"—the ability of its renewable energy resources to satisfy PG&E's RPS requirements.[109] PG&E's compliance with its "Minimum Retained RPS" requirement, adopted in D.20-02-047, directly impacts the RPS value of its PCIA-eligible portfolio. In the event PG&E's bundled net RPS position is forecasted to fall below its bundled RPS target for the applicable ERRA year (which it routinely does), PG&E must retain RECs to make up the shortfall.[110] The RECs PG&E uses to meet its Minimum Retained RPS requirement, the value PG&E assigns those RECs, and the specific PCIA vintages that pay for and receive credit for those RECs directly impact the PCIA rates that customers pay.

RECs remain active in Western Renewable Energy Generation Information System (WREGIS) for a period of three years after their generation, during which they can be sold to another counterparty for its own compliance requirement. PG&E categorizes those RECs as "Unsold RPS" if they have not been used towards PG&E's RPS compliance requirements, and if the RECs have been offered for sale but not sold.[111] After this three-year period, RECs must be

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109 *See supra* Section V.B.

110 Exh. PG&E-01 at 5-12.

111 Exh. CalCCA-01C at 25.

retired in WREGIS, meaning they cannot be sold.[112] Those retired RECS are considered "banked RECs" only if PG&E's quantitative procurement requirement for a compliance period is already met.[113]

2. PG&E and CalCCA Agree PG&E Should Apply Unsold RPS Volumes Towards its 2026 and Forecast 2027 Minimum Retained RPS

PG&E forecasted a shortfall towards its 2027 Minimum Retained RPS requirement in this year's Application, similar to several prior years.[114] PG&E stated in its Prepared Testimony that it intended to cover its Minimum Retained RPS shortfall with banked RECs, in this case pre-2019 Banked RECs.[115] In response, CalCCA recommended PG&E use Unsold RPS volumes that have been retired for RPS compliance purposes before using pre-2019 banked RECs.[116]

On rebuttal, PG&E stated it would apply its Unsold RPS volumes towards its Minimum Retained RPS requirements consistent with CalCCA's recommendation, but not for the reasons CalCCA witness Matley offered in his testimony. According to PG&E, "[f]ollowing a review of applicable RPS compliance rules as expiration dates for Unsold RECs were approaching, PG&E began transferring its Unsold RPS to its WREGIS retirement accounts in order to keep the RECs from expiring and reducing the amount of RECs available for PG&E and the broader market for use towards meeting future RPS compliance requirements."[117] PG&E asserts that it cannot convert those Unsold RECs to Banked RECs because of RPS compliance rules and thus must use them

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112 *Id*.

113 Exh. PG&E-04 at 4-2.

114 Exh. PG&E-01 at 8-17.

115 *Id*. at 8-17 to 8-18; Table 8-4.

116 Exh. CalCCA-01C at 24.

117 Exh. PG&E-04 at 4-3.

towards its expected 2027 RPS shortfall.[118] On August 3, 2026, PG&E filed its RPS Compliance Report for 2025, and that report included 1,643,425 megawatt-hours of RECs retired to PG&E's 2025 WREGIS account.[119] In discovery, PG&E indicated it also retired 1,688,041 megawatt-hours of RECs to its 2026 WREGIS account.[120] PG&E plans on retiring remaining Unsold RECs (489,592 megawatt-hours[121]) to either its 2026 or 2027 WREGIS account.[122] According to PG&E, given that it is currently expected to be physically short of meeting its Compliance Period 5 (2025-2027) requirements, it expects to fully utilize all Unsold RPS towards meeting those requirements.[123] Consistent with D.19-10-001, which requires PG&E to retain RPS based on the volume of RPS used for IOU compliance, PG&E will value those Unsold RPS volumes at the applicable year's MPB.[124] For example, if an Unsold REC is used towards PG&E's 2026 Minimum Retained RPS requirement, PG&E would value the Unsold REC at the 2026 RPS MPB.[125]

CalCCA supports PG&E's use of Unsold RPS volumes towards its Minimum Retained RPS requirement, and agrees those RECs should be retained and valued at the applicable year's RPS MPB. CalCCA will review PG&E's workpapers in the October Update to evaluate PG&E's

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118 *Id*. at 4-2.

119 *Id*. According to PG&E, it retired those RECs to the 2025 WREGIS account on 12/19/2025, 1/15/2026, 2/24/2026, 3/24/2026 and 6/29/2026 – as those RECs approached the 36 month deadline for January through April 2023 vintages (January 2023 vintage RECs needed to be retired by 12/31/2025, for example). Exh. CalCCA-09C (PG&E response to CalCCA DR 10.06).

120 Exh. CalCCA-09C (PG&E response to CalCCA DR 10.06).

121 *Id*.

122 Exh. PG&E-04 at 4-2.

123 *Id*.

124 *Id*.

125 Exh. CalCCA-09C (PG&E response to CalCCA DR 10.06).

use and valuation of Unsold RPS volumes. Below, however, CalCCA discusses a discrete aspect of PG&E's proposal to use Unsold RPS volumes: the impact of its use of Unsold RPS volumes on 2025 Minimum Retained RPS entries, and its displacement of RECs previously used towards its 2025 Minimum Retained RPS requirement.

3. The Commission Should Limit PG&E's Ability to Displace the RECs it Applied Towards Prior Years' Minimum Retained RPS Entries.

In response to CalCCA discovery, PG&E clarified it expects Unsold RPS to displace banked RECs previously used towards 2025 and 2026 RPS requirements.[126] It also acknowledged that the volume of banked RECs being applied in 2025 has been updated and is a different quantity than the volume shown in PG&E's Fall Update in the 2026 ERRA Forecast case (A.25-05-011) and the volume shown in PG&E's 2025 ERRA Compliance proceeding (A.26-02-019).[127]

PG&E chalks these changes up to the multi-year nature of RPS compliance periods. According to PG&E, the multi-year nature of RPS compliance periods (for example, Compliance Period 5 runs from 2025-2027) results in PG&E making updates, corrections, and changes to the REC volumes and specific RECs it uses for bundled customer compliance throughout the period.[128] In other words, even though we are in calendar year 2026, PG&E continues to make changes to the RECs it uses for bundled customer compliance in 2025. This, in turn, necessitates adjustments to Minimum Retained RPS entries for 2025, pursuant to D.19-10-001.[129]

As discussed above, in the interest of portfolio optimization, CalCCA supports PG&E's proposal to use expiring Unsold REC volumes towards its RPS compliance requirements. As

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126 *Id*. (PG&E response to CalCCA DR 10.06(c)).

127 Exh. CalCCA-12 (PG&E response to CalCCA DR 12.02).

128 Exh. CalCCA-13 (PG&E response to CalCCA DR 12.03).

129 *Id*.

PG&E explains, this will "keep the RECs from expiring and reducing the amount of RECs available to PG&E and the broader market for use towards meeting future RPS compliance requirements."[130]

But the Commission should expressly caution that its approval of PG&E's proposal is not a broad authorization for PG&E to unilaterally make changes to its Minimum Retained RPS accounting from prior years. Parties closely examine (and routinely litigate) PG&E's RPS accounting in ERRA Forecast and Compliance cases, including PG&E's Minimum Retained RPS entries and any banked RECs PG&E applies towards the Minimum Retained RPS requirement. PG&E and CalCCA already litigated PG&E's use of banked RECs towards its 2025 Minimum Retained RPS requirement, for example, in the 2024 ERRA Forecast case (A.24-05-009),[131] and the 2025 ERRA Forecast Case (A.25-05-011).[132] In each case, the Commission approved revenue requirements, including PCIA revenue requirements, that reflected the specific RECs PG&E proposed to use towards its Minimum Retained RPS requirement. The Commission should therefore expressly limit PG&E's ability to displace the RECs it previously applied towards a prior year's Minimum Retained RPS requirement, and permit PG&E to make changes for 2025 only to the extent it displaces previously-used banked RECs with expiring Unsold RPS volumes.

CalCCA will review the impact of PG&E's use of Unsold RPS volumes in the October Update, and reserves its right to address and further contest this issue following that review.

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130 Exh. PG&E-04 at 4-3.

131 D.24-12-038 at 16-17.

132 D.25-12-027 at 26-32.

C. THE COMMISSION SHOULD REVISIT THE LOAD FORECAST MEET AND CONFER PROCESS IN THE PCIA OIR

PG&E forecasts sales and peak demand growth across its service area in its annual ERRA Forecast proceedings. That forecast determines which and to what extent bundled and unbundled customers bear the PCIA Revenue Requirement.[133] In developing its sales and peak demand forecasts, PG&E engages in a meet-and-confer with CCAs in its service area, and has historically incorporated CCAs' forecasts into its overall forecasts.[134]

The Commission mandated the ERRA Forecast meet-and-confer process in the 2016 ERRA Forecast proceeding, long before the current wave of hyperscaler data centers that support the modern artificial intelligence buildout.[135] It did not contemplate the significant uncertainty inherent in data center load forecasting.

Accurate forecasts help reduce PCIA rate volatility, whereas significant over- or under-forecasts can harm CCAs and their customers in particular. That is because CCAs and their customers have limited insight into and ability to control PCIA rate swings,[136] and as discussed below, the risk of PCIA rate volatility is likely concentrated into specific PCIA vintage rates paid by CCA customers rather than the PCIA vintage rates paid by bundled customers.[137] In order to improve the accuracy of PG&E's load forecasts and ensure that PG&E and CCAs in its service area remain coordinated in an era of rapid load growth, the Commission should revisit the meet-and-confer process in the pending PCIA rulemaking.

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133 *See* supra Section V.

134 Exh. CalCCA-14C (PG&E response to CalCCA DR 10.01(c)).

135 D.16-12-038 at Conclusion of Law (COL) 3.

136 Exh. CalCCA-01C at 28.

137 *Id*. at 27.

1. Inaccuracies in PG&E's Data Center Load Forecast Can Introduce Volatility into the PCIA

In its ERRA proceedings, PG&E forecasts sales and peak demand sales for the following year. It then allocates the PCIA revenue requirement across all load, bundled and unbundled, according to customer vintage and rate class.[138] In other words, PG&E's load forecasts act as the denominator that converts the PCIA revenue requirement into a PCIA charge per kWh. In the following year's ERRA proceeding, the Commission trues up actual sales against forecasted sales. In the instant Application, PG&E will segment its 2027 sales forecast among customer types, including data centers which fall under the large commercial and industrial customer class.[139]

In his Direct Testimony, CalCCA witness Matley illustrated the impact that one 500 MW data center at 90% load factor can have on PCIA rates for all CCA customers. Witness Matley concluded that if that data center's start of service is delayed by just one year, that would create an approximately 5% discrepancy between forecasted and actual sales.[140] When translated into PCIA rates, that could amount to an approximate increase in $0.004/kWh in the customer vintage for the hypothetical data center and $0.001 kWh for all other vintages.[141] In short, the risks of PCIA rate volatility are not distributed evenly across PG&E's bundled and CCA customers. While PG&E does not agree with the specific calculations witness Matley presents, it nevertheless agrees with his premise, which is that load forecast variance can contribute to undercollections or overcollections in the PABA.[142]

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138 *See* supra Section V.C.

139 Exh. PG&E-01 at 2-11:8-9.

140 Exh. CalCCA-01 at 28:8-15.

141 *Id*. at 29:1-8.

142 Exh. PG&E-04 at 2-7.

2. The Meet and Confer Process Is Outdated and Requires Reform

PG&E has made several important updates to its forecasting methodology that acknowledge that data center load growth is unlike load growth from other large commercial and industrial customers. For example, PG&E has excluded previous historical large data center electricity usage from its regression models, instead accounting for the current wave of data centers separately.[143] PG&E's data center load forecasting relies on its large load interconnection application queue.[144] PG&E takes into account the maturity of projects in its application queue and accounts for certain data-center-specific factors, such as materialization rate and a load factor tied to data centers.[145]

These updates are positive steps. However, the meet-and-confer process between PG&E and CCAs also requires updates in order to ensure PG&E's load forecasts are as accurate as possible, which will in turn reduce the risk of PCIA rate volatility discussed above.

The meet-and-confer process is a required step in each year's ERRA Forecast proceeding during which PG&E works with CCAs to develop load forecasts.[146] In its 2017 ERRA Forecast, PG&E committed to exchange load forecasts with CCAs, working collaboratively to incorporate the most accurate load forecasts into both its ERRA Application and October Update.[147] PG&E correctly assumes that new data center load in CCA service territory will default to CCA service, not PG&E service, unless the customer opts out.[148] That assumption underlines the importance of

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143 Exh. PG&E-01 at 2-4:21-26.

144 *Id*. at 2-11:18-34.

145 *Id*. at 2-11:18–2:12:10.

146 D.16-12-038 at 6. *See also* D.20-03-019 at OP 1.

147 *See* D.16-12-038 at 13-14. *See also* D.20-03-019 at OP 1.

148 Exh. PG&E-01 at 2-12:27-28.

PG&E's annual meet-and-confer process with CCAs, because as discussed above, inaccurate forecasts can cause whiplash for CCAs' customers.

As part of this year's meet-and-confer process, PG&E submitted e-mail requests for load forecasts from the 12 CCAs in PG&E's territory and received forecasts from all 12.[149] For its Prepared Testimony, PG&E only incorporated load forecasts from the seven CCAs that forecasted no data center load growth.[150] Of the five CCAs whose forecasts PG&E did not incorporate, three load forecasts were rejected largely because PG&E disagreed with the respective CCA's data center load forecast specifically.[151] PG&E unilaterally determined that those three CCAs' data center load forecasts relied on outdated assumptions or historical application data.[152] Besides good-faith discussions during the period between PG&E's Prepared Testimony and October Update, those CCAs are entitled to no recourse.[153] The current process provides no pathway to resolve differences in forecast load—when PG&E and a CCA are not able to agree on the data center load forecast, then PG&E will use its own forecast.[154] This potential outcome is problematic because CCAs have unique insight into the certainty and timing of data center loads through the local permitting, zoning, and land-use requirements of the municipalities comprising the CCAs.[155]

The current meet-and-confer process was established a decade ago, well before today's wave of data centers that support artificial intelligence.[156] In the decade since that meet-and-confer

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149 *Id*. at 2-19:16-25.

150 *Id*.

151 Exh. PG&E-04 at 2-4:26-27.

152 Exh. CalCCA-16 (PG&E response to CalCCA DR 10.03(b)).

153 Exh. CalCCA-14 (PG&E response to CalCCA DR 10.01(f)).

154 *See* Exh. CalCCA-01 at 31; Exh. CalCCA-15 (PG&E response to CalCCA DR 10.02).

155 Exh. CalCCA-01 at 32.

156 D.16-12-038 at COL 3.

process, load growth was steady and predictable. The existing meet-and-confer process worked well when PG&E and the CCAs in its service area agreed on load growth forecasts. In the past three October Updates, PG&E incorporated all of the CCA load forecasts into its overall load forecast.[157]

Today, each hyperscaler data center is several times larger than legacy data centers, which amplifies the impact of even one data center customer on the load forecast.[158] In an era when the distribution utility (PG&E) and the load serving entity (a CCA) may disagree about how to model unprecedented load growth – and those disagreements can cause volatility in PCIA rates borne by unbundled customers – the meet-and-confer process must be reformed to ensure accurate forecasts. CCAs are well-positioned to anticipate and model load growth because of their status serving most customer load, access to local government interconnection queue data, and personal relationships with inbound data center customers. A more collaborative process between parties will only strengthen the accuracy and robustness of their composite load forecasts.

The Commission should therefore reform the meet-and-confer process. As a part of that reform process, the Commission should consider treating CCA data center load forecasts as a rebuttable presumption.[159] To the extent PG&E possesses additional relevant information based on discussions with prospective customers or any other source, PG&E should be required to rebut the CCA forecast based on that information (confidentially, if necessary) to prove the accuracy of its conflicting data center load forecast.[160] The Commission should evaluate and adopt reforms to

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157 Exh. CalCCA-14 (PG&E response to CalCCA DR 10.01(c)).

158 Exh. CalCCA-01 at 27:14-21.

159 *Id*. at 32.

160 *Id*.

the data center load forecasting process in the PCIA OIR currently underway. Although this issue is particularly acute and urgent in PG&E's territory at the moment, it will likely impact SCE and San Diego Gas & Electric Company's service territories over time.[161]

VI. UNCONTESTED ISSUES

In addition to the contested issues discussed at length above, CalCCA investigated several other issues raised by PG&E's Application. Below, this brief discusses three of those issues. While these issues are currently uncontested, CalCCA reserves the right to address and contest these issues following its review of PG&E's October Update testimony.

A. RESOURCE ADEQUACY VALUATION METHODOLOGY AND THE IMPACT OF D.26-07-008

In its Supplemental Testimony, PG&E proposed changes in its RA Valuation Methodology stemming from D.26-07-008. In that decision, the Commission adopted reforms that better align RA capacity calculations with the real-world operational experience for three distinct kinds of resources: energy storage resources, energy-only resources, and long-duration storage resources.[162]

1. CalCCA Supports PG&E's Update to Its RA Valuation Methodology for Energy Storage Resources

For energy storage resources, D.26-07-008 modifies the capacity attributable to a battery by accounting for "foldback."[163] Like a phone battery that stops charging at 80% and enters low power mode at 20%, a utility-scale battery system may limit its output when reaching pre-defined thresholds of charge in order to reduce instances of deep discharge, known as foldback. While this

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161 *Id*.

162 Exh. PG&E-03 at 7:6-9.

163 Exh. CalCCA-01 at 20:18–21:2.

maintains battery health, foldback also reduces the continuous capacity that a battery delivers over its full discharge duration. PG&E proposes to change its calculation of battery energy storage to use Maximum Continuous Energy instead of Net Qualifying Capacity to account for foldback.[164]

CalCCA does not object in concept to PG&E's proposed modification because it is reasonable for PG&E to use the most accurate and up-to-date information in calculating the retained RA attributable to battery energy storage systems. However, PG&E has not yet applied its new methodology to its calculation of RA value, and therefore the details of PG&E's proposal will require review in the October Update. CalCCA reserves the right to address and contest PG&E's proposed change to its RA valuation methodology in comments on the October Update.

2. PG&E Has Not Addressed the Directives in D.26-07-008 Related to Energy-Only and Long-Duration Storage Resources

D.26-07-008 also addresses energy-only resources and long-duration storage resources. The Commission made modifications to allow excess energy from co-located energy-only resources to account for certain charging sufficiency requirements.[165] The Commission's change acknowledges that while energy-only resources co-located with energy storage may not have RA capacity value themselves, energy-only resources reduce the need for energy storage systems to utilize RA capacity from other resources.[166] Thus, energy-only resources that are co-located with energy-storage reduce the need for those storage systems to utilize RA capacity from other resources and should therefore not experience the full RA capacity reduction associated with

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164 Exh. PG&E-03 at 7:23-31.

165 D.26-07-008, *Decision Adopting Local Capacity Obligations for 2027-2029, Flexible Capacity Obligations for 2027, and Program Refinements*, R.25-10-003 (July 2, 2026), at OP 8.

166 *Id*. at 38-39.

charging.[167] PG&E has at least one applicable co-located energy-only resource but has not proposed an update to its RA valuation methodology effectuating the Commission's change.[168]

The Commission also modified RA valuations and charging sufficiency requirements for long-duration energy storage resources. Those long-duration energy storage resources can now count their capacity across the 24-hour SoD period up to the resource's capabilities, based on certain other characteristics.[169] That change reflects the fact that long-duration energy storage resources can shift charging across multiple days and preserve a meaningful charging obligation.[170] PG&E has not yet proposed to update its RA valuation methodology to effectuate that change.

While PG&E does not currently have any resources that would qualify as long-duration energy storage,[171] PG&E should nevertheless update its RA Valuation Methodology to more comprehensively address each of the directives from D.26-07-008. In its Rebuttal Testimony, PG&E states that it "intends to implement D.26-07-008 to the extent possible" but also states that "[c]ertain aspects of the decision depend on modifications to the RA Market Reference Data and related implementation steps that are outside of PG&E's control and have not yet been completed."[172] While CalCCA does not contest PG&E's approach at this time, CalCCA reserves the right to further address and contest PG&E's implementation of D.26-07-008 following its review of the October Update.

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167 Id.

168 Exh. CalCCA-01, Attachment RAM-3 (PG&E's Response to DR CalCCA 006-Q009).

169 D.26-07-008 at OP 10.

170 *Id*. at 51.

171 Exh. CalCCA-01, Attachment RAM-3 (PG&E's Response to DR CalCCA 009-Q007).

172 Exh. PG&E-04 at 3-8.

B. INTERIM GENERAL RATE CASE REVENUE REQUIREMENT

PG&E filed its GRC in May 2025 for the 2027-2030 time period.[173] PG&E's forecasted revenue requirement showed a significant $300 million increase in Electric Generation Revenue Requirement attributable to utility-owned generation as compared to 2026, which translates to an increase in the PCIA of approximately $.004 per kWh across all vintages.[174]

The current timeline of the GRC anticipates a final decision by May 2027, too late to include the updated Electric Generation Revenue Requirement in 2027 PCIA rates.[175] PG&E has filed a motion in the GRC to implement Interim Rates effective January 1, 2027, at either 55 percent, 75 percent, or 85 percent of its initial requested revenue requirement increase.[176] The Commission's proposed decision in the 2027 GRC case allows PG&E to charge Interim Rates at 55 percent of its requested revenue requirement for electric generation and distribution.[177] To the extent the Commission approves an interim revenue requirement in the 2027 GRC, PG&E and CalCCA agree that PG&E should implement the electric generation portion of that revenue requirement into 2027 rates.[178]

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173 A.25-05-009, *Application of Pacific Gas and Electric Company for Authority, Among Other Things, to Increase Rates and Charges for Electric and Gas Service Effective on January 1, 2027. (U 39 M)* (May 15, 2025).

174 Exh. CalCCA-01 at 33:11–34:3.

175 *Id*. at 34:3-5.

176 *Id*. at 34:9-11.

177 A.25-05-009, *Proposed Decision of ALJ Fox Authorizing Interim Rate Authority* at 12-13 (Sept. 23, 2026).

178 Exh. PG&E-04 at 5-2.

C. PCIA CALCULATION CORRECTIONS

In its review of PG&E's initial application, CalCCA identified several errors in PG&E's testimony and workpapers.[179] CalCCA raised those errors via discovery, and PG&E confirmed those errors in its responses.[180] PG&E ultimately resolved them in its errata filing submitted July 17, 2026.[181] The errors CalCCA identified are no longer contested. CalCCA notes the discovery process helped identify and resolve these issues, ultimately helping to produce accurate rates.

VII. CONCLUSION

For the foregoing reasons, CalCCA requests the Commission adopt the recommendations listed in CalCCA's Summary of Recommendations. CalCCA reserves the right to modify those recommendations based on updated information presented in PG&E's October Update and to address other issues raised therein via comments on the October Update or any further process the Commission might adopt.

October 21, 2026

Respectfully submitted,



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[179] Fossil Unit Vintaging, Sales Forecast, Retained RPS, and Retained RA. *See* Exh. CalCCA-01 at 35:11–36:14.

[180] *Id*. at 35-36.

[181] Exh. PG&E-02 at 8-27, 12-8, 13-AtchA-2.

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future.	R.21-06-017

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON THE PROPOSED DECISION ADOPTING AN APPLICATION PROCESS FOR UTILITY DISTRIBUTED ENERGY RESOURCES ORCHESTRATION AND ORDERING UTILITIES TO INCORPORATE LOAD FLEXIBILITY SCENARIOS INTO THEIR DISTRIBUTION PLANNING AND EXECUTION PROCESSES

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SUMMARY OF RECOMMENDATIONS[1]

In response to party Opening Comments, CalCCA recommends the following:

- The proceeding should remain open, or a successor proceeding should be opened, to provide a venue to resolve scoped conflict of interest and market power issues and develop the DER Orchestration Framework on the record, as recommended by the Joint Parties and CalSSA; and

- The proposed process for adopting a DER Orchestration Framework should be modified as recommended by PG&E, SDG&E, United, and the Joint Parties, but with CalCCA's recommended three-phase process:

    - **Phase 1:** The Working Group should develop governance and oversight rules to address conflict of interest and market power issues, culminating in a report, party comments, and a Phase 1 Commission Decision;

    - **Phase 2:** After the Phase 1 Decision, the Working Group should develop the DER Orchestration Framework and IOU Joint Application requirements, culminating in a report, party comments, and a Phase 2 Commission Decision; and

    - **Phase 3:** The IOU Joint Application should be filed.

[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 REPLY COMMENTS ON THE PROPOSED DECISION ADOPTING AN APPLICATION PROCESS FOR UTILITY DISTRIBUTED ENERGY RESOURCES ORCHESTRATION AND ORDERING UTILITIES TO INCORPORATE LOAD FLEXIBILITY SCENARIOS INTO THEIR DISTRIBUTION PLANNING AND EXECUTION PROCESSES

The California Community Choice Association (CalCCA) submits these reply comments pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure[2] on the proposed *Decision Adopting an Application Process for Utility Distributed Energy Resources Orchestration and Ordering Utilities to Incorporate Load Flexibility Scenarios into Their Distribution Planning and Execution Processes*[3] (PD), dated September 25, 2026; and Administrative Law Judge Jack Chang's procedural email dated October 6, 2026, clarifying the date for party opening and reply comments.

I. INTRODUCTION

Party Opening Comments[4] demonstrate the need to further refine the PD's process for developing the distributed energy resources (DER) orchestration framework. Many parties echo the concerns raised in CalCCA's Opening Comments on the need to address the investor-owned utility (IOU)[5] conflict of interest and market power concerns *prior to* the establishment of a

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

[3] Proposed *Decision Adopting an Application Process for Utility Distributed Energy Resources Orchestration and Ordering Utilities to Incorporate Load Flexibility Scenarios into Their Distribution Planning and Execution Processes*, Rulemaking (R.21-06-017) (Sept. 25, 2026).

[4] References to "Opening Comments" refer to those filed on or about October 19, 2026, into this proceeding.

[5] As used herein, "IOUs" refer collectively to Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE).

proposed framework.[6] Several parties also agree that foundational issues, including governance, must be addressed *before* IOUs submit their implementation applications.[7]

In response to party Opening Comments, CalCCA recommends the following:

- The proceeding should remain open, or a successor proceeding should be opened, to provide a venue to resolve scoped conflict of interest and market power issues and develop the DER Orchestration Framework on the record, as recommended by the Joint Parties and CalSSA; and
- The proposed process for adopting a DER Orchestration Framework should be modified as recommended by PG&E, SDG&E, United, and the Joint Parties, but with CalCCA's recommended three-phase process:
    - **Phase 1:** The Working Group should develop governance and oversight rules to address conflict of interest and market power issues, culminating in a report, party comments, and a Phase 1 Commission Decision;
    - **Phase 2:** After the Phase 1 Decision, the Working Group should develop the DER Orchestration Framework and IOU Joint Application requirements, culminating in a report, party comments, and a Phase 2 Commission Decision; and
    - **Phase 3:** The IOU Joint Application should be filed.

II. THE PROCEEDING SHOULD REMAIN OPEN, OR A SUCCESSOR PROCEEDING SHOULD BE OPENED, TO PROVIDE A VENUE TO RESOLVE SCOPED CONFLICT OF INTEREST ISSUES AND DEVELOP THE ORCHESTRATION FRAMEWORK ON THE RECORD AS RECOMMENDED BY THE JOINT PARTIES AND CALSSA

The proceeding should remain open, or a successor proceeding should be opened, to provide a venue for the Commission to resolve scoped conflict of interest issues and to develop the orchestration framework on the record. As CalCCA points out in Opening Comments, the Commission has failed to resolve the issues scoped in the proceeding regarding IOU conflict of interest and market power.[8] Joint Parties' Opening Comments mirror CalCCA's call to extend the existing proceeding, stating:

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[6] Opening Comments: CalCCA at 4-6; Joint Opening Comments of Clean Coalition, Center for Biological Diversity, 350 Bay Area, Vote Solar, the Climate Center, and Microgrid Resources Coalition (Joint Parties) at 5-7; Environmental Defense Fund at 5; California Solar and Storage Association (CalSSA) at 3-4; California Efficiency + Demand Management Council at 6-8; Utility Consumers' Action Network at 6-7; and Advanced Energy United (United) at 2-3, 11-12.

[7] Opening Comments: PG&E at 4; SDG&E at 4-5; Joint Parties at 5-7; United at 2-3.

[8] CalCCA Opening Comments, at 1-4, 8.

> The Commission should . . . preserve Track 2 for a determination of these outstanding governance and incentive-alignment questions, rather than treating referral to the working group or Joint IOU Application as sufficient to resolve them.[9]

In addition, CalSSA proposes that the Commission open a successor proceeding to address unresolved issues, arguing that:

> Addressing conflict of interest is crucial. Since the only components that have been finalized are guiding principles, and the only intermediate step proposed by the PD is an informal working group that has no binding influence on the IOUs' applications, going straight to applications allows IOUs to propose applications that are divorced from stakeholder input.[10]

While the Commission proposes that framework development be conducted through the Working Group process, this Working Group will be conducted through an IOU-led consultant, and the Report will not be subject to Commission review or stakeholder comments until the Report is attached to the Joint IOU Application. Instead, as set forth in CalCCA's Opening Comments and as addressed below, refinement of the Working Group process and direction from the Commission is necessary to ensure the conflict-of-interest issues are adequately addressed and that the orchestration framework is sufficiently developed prior to the IOU applications. Therefore, this proceeding should remain open, or a successor proceeding should be opened, to allow the resolution of the conflict-of-interest issues and development of the framework in a formal proceeding.

III. PARTY OPENING COMMENTS DEMONSTRATE THE NEED TO CLARIFY THE PROPOSED PROCESS TO ADDRESS FOUNDATIONAL GOVERNANCE ISSUES BEFORE DEVELOPING THE FRAMEWORK APPLICATIONS

CalCCA agrees with multiple parties seeking refinement of the PD's proposed Working Group process and the IOU Joint application. While parties differ on the actual process, parties including PG&E, SDG&E, United, and the Joint Parties all agree that the Commission should address foundational issues, including governance, before requiring the IOUs to submit DER orchestration proposals. PG&E recommends a two-phased approach, with the first phase focused on resolving foundational questions, including governance models:

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[9] Joint Parties Opening Comments, at 7.

[10] CalSSA Opening Comments, at 3.

> Requiring detailed IOU implementation plans before the Commission has acted on the common framework could result in implementation proposals based on assumptions or requirements that subsequently change.[11]

Similarly, SDG&E recommends addressing foundational issues during the Working Group process, warning that "[d]eveloping program proposals before those standards are settled would require the utilities to design programs while the governing rules remain under development."[12]

United also asserts that "[t]he structure of the PD leaves the IOUs to propose the terms on which they compete with third parties, and the Commission should address that before the IOUs design their applications."[13]

Echoing CalCCA's call for a two-phase Working Group process to address governance and oversight issues,[14] the Joint Parties recommend addressing "governance principles, market-participant roles, competitive neutrality, data access, independent monitoring, and minimum application requirements."[15] The Joint Parties continue, stating:

> Critically, the Phase 1 report must lead to a Commission determination of minimum governance requirements before the IOUs finalize their framework and file the Joint IOU Application. Otherwise, the working group risks becoming another advisory process whose recommendations can be selectively incorporated into IOU proposals without binding Commission direction.[16]

CalCCA agrees with these parties that failing to address foundational issues, including governance, before submitting the framework proposals will either require the IOUs to revise their proposals after the fact or allow the selective adoption of rules favorable to the IOUs. Considering party proposals on process, CalCCA refines its Opening Comments to recommend a three-phase process:

> **Phase 1:** Working Group (facilitated by Energy Division-led consultant) develops governance and oversight principles, addressing conflict of interest and market power mitigation of an IOU-led DSO framework. The consultant will submit the report into the record of the Commission proceeding after which parties file formal comments on the record, culminating with a Phase 1 Commission Decision;

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11 PG&E Opening Comments, at 4.

12 SDG&E Opening Comments, at 4 (stating that "[p]arallel development therefore invites inconsistent assumptions, underdeveloped proposals, and substantial revisions after the framework is adopted").

13 United Opening Comments, at 3.

14 CalCCA Opening Comments, at 8-10.

15 Joint Parties Opening Comments, at 6.

16 *Ibid*.

Phase 2: Working Group continues, incorporating the Phase 1 Commission Decision on governance and oversight into a DER orchestration framework, incorporating all foundational requirements to apply to all three IOUs. The framework will also include IOU application requirements. The consultant will submit a report into the record of the Commission proceeding, after which parties file formal comments on the record, culminating with a Phase 2 Commission Decision;[17] and

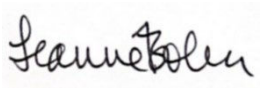
Phase 3: Based on the direction provided in the Phase 2 Decision, the IOUs submit the Joint DER Orchestration Application.

With this three-phased process, adequate time and input from stakeholders and the Commission will result in a robust, clearly defined DSO orchestration framework, with safeguards to mitigate conflicts of interest and market power.

IV. CONCLUSION

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

Respectfully submitted,



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October 26, 2026

[17] Parties also recommend a Tier 3 Advice Letter (AL) process to seek approval of the framework developed by the Working Group. See United Opening Comments, at 3 (arguing that using a Tier 3 AL to approve the framework ensures that "the Commission rules on the foundational framework issues, including governance and safeguards against utility self-preference, before the IOUs develop their implementation proposals."); see also SCE Opening Comments, at 2 (proposing that the joint framework be submitted using a Tier 3 AL, reasoning that it "is appropriate given the amount of stakeholder engagement anticipated in the Working Group sessions, which will obviate the need for an additional stakeholder process via an application."); see also SDG&E Opening Comments, at 3 (a Tier 3 AL "preserves the opportunity for stakeholders to participate in the Working Group, comment on the draft report, protest or respond to the advice letter, and make further comments on the draft resolution before the Commission acts."). While a Tier 3 AL process allows stakeholders to submit responses or protests and would be better than not having Commission consideration at all, it may not permit the development of a fulsome record. Given the complexity and breadth of issues related to governance and oversight issues, as well as the overall DER orchestration framework and the IOU application requirements, CalCCA recommends keeping the proceeding open and ensuring adequate record development and Commission and stakeholder involvement rather than relying on the more expedited Tier 3 AL process.

Docket No.: A.24-09-014

Exhibit No.: _____

Date: October 30, 2026

Witness: Kyra J. Coyle

PREPARED DIRECT TESTIMONY OF KYRA J. COYLE

ON BEHALF OF

THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION

REGARDING PG&E'S STOP-GAP HOURLY FLEX PRICING EXTENSION PROPOSAL (EXHIBIT PG&E-6)

IN PG&E'S GENERAL RATE CASE PHASE II APPLICATION

EXECUTIVE SUMMARY OF RECOMMENDATIONS

This testimony presents the recommendations of CalCCA[1] concerning the Stop-Gap Hourly Flex Pricing Extension Proposal in the *Application of Pacific Gas and Electric Company to Revise its Electric Marginal Costs, Revenue Allocation, and Rate Design*, submitted on September 30, 2024.

CalCCA recommends the Commission:

- Reject PG&E's proposal to discontinue the CCA incentive, and direct PG&E to extend the funding for CCA participation in the HFP pilots, including through any HFP 1.0 extension and HFP 2.0, on the terms the Commission adopted in D.24-01-032: $20 per kW-yr of enrollment in the CCA's service territory, subject to a per-pilot cap no lower than $1,800,000. The Commission should maintain this funding because PG&E: (1) failed to perform any analysis of the impact of eliminating the incentive on CCA recruitment or load response; (2) failed to consult CCAs on these proposed changes; (3) disregarded the Commission's stated purpose for the incentive, which was to increase enrollment; and (4) paradoxically proposes to fund ASPs and its own CCA-related administration while cutting off CCAs.
- Decline to approve, at this time, PG&E's proposal to replace subscriptions with the RNA because PG&E: (1) failed to perform any sensitivity or cost-shift analysis of the RNA; and (2) admits the RNA does not ensure customer-level revenue neutrality. The Commission should instead:
    - Adopt PG&E's proposal for credit-and-charge billing, while maintaining the existing HFP subscription design;
    - Permit PG&E to propose targeted, incremental refinements to the design based on the final HFP 1.0 evaluation and the RTP Impact Assessment, with an opportunity for CCAs and other stakeholders to review and comment before any change is implemented; and
    - Prioritize customer education and direct PG&E to submit a customer education plan, in consultation with CCAs and ASPs, and authorize PG&E to reallocate funds within its approved implementation budget to support it.

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

- In the alternative, if the Commission adopts the RNA, the Commission should:
    - Require PG&E to first serve, before HFP 2.0 is implemented: (1) a quantitative analysis of the RNA's customer-level, class-level, and participant/non-participant cost incidence, including the distribution of resulting credits and charges among customers within each rate schedule; (2) the results of its research on a fixed monthly charge alternative, together with a schedule for completing it; and (3) a commitment to report RNA outcomes by load-serving entity;
    - Confirm that CCAs retain the ability to modify RNA values for their own customers, and require PG&E to provide itemized estimates of the costs CCAs would bear under each customization option, which PG&E has said are the CCAs' responsibility;
    - Require PG&E to document the CCA customization options PG&E has confirmed in discovery in its implementing advice letter or in supplemental testimony;
    - Require PG&E to clarify, in supplemental testimony, how the exit ramp would apply to CCA customers;
    - Direct PG&E to preserve subscriptions as an optional feature, as PG&E itself says it may consider after HFP 2.0;
    - Require non-residential accounts to be served by an automation technology or participate with an automation service provider as a condition to enroll in the HFP to limit cost shifts to non-participating customers; and
    - Adopt CalCCA's recommendations regarding customer education described above.
- Direct PG&E to supplement its testimony to itemize the implementation costs recorded in the Dynamic and Real-Time Pricing Memorandum Account and identify any that are attributable solely to bundled generation service, which should be recovered from bundled customers only.
- Reject PG&E's open-ended request for post-decision cost-update authority unless the Commission requires bounding cost estimates before a final decision and adopts the guardrails described in this testimony.
- Require PG&E to support its program administration forecast with actual staffing and cost detail as a condition of recovery.

- Direct PG&E to convene a stakeholder process with CCAs to define the data, frequency, and confidentiality protections for any exchange of CCA program data used to prevent double compensation.

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ATTACHMENTS

Attachment KJC-1 – CV of Kyra J. Coyle
Attachment KJC-2 – PG&E Responses to CalCCA Data Requests

I. INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

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

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

Q: Please describe your experience and qualifications.

A: I have over 15 years of experience in the utility, mining, and public accounting sectors. My expertise includes utility revenue requirement analyses, strategic planning, project management, contract negotiations, financial modeling, regulatory affairs, budgeting, forecasting, and regulatory accounting. My rate-related projects have included studies to develop retail electric, natural gas, transmission, ancillary service, standby, and special contract rates. I have provided expert witness testimony before several public utility commissions, including those in Alaska, Texas, California, Utah, Oregon, Indiana, and Wyoming, as well as before the Federal Energy Regulatory Commission (FERC). I previously submitted direct testimony in this proceeding on March 9, 2026, on behalf of the California Community Choice Association (CalCCA) regarding Pacific Gas and Electric Company's (PG&E) proposed community choice aggregator (CCA) Service Fees and Provider of Last Resort fee. A summary of my qualifications is provided within **Attachment KJC-1** to this testimony.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of CalCCA. CalCCA represents the interests of 24 CCAs in California, including 11 CCAs that serve PG&E's delivery service customers. Each of those CCAs is governed by a Board of Directors comprised of elected officials who represent the individual cities and counties the CCA serves, or an elected City Council. CleanPowerSF is the CCA program developed and operated by the City and County of San Francisco, through the San Francisco Public Utilities Commission. SJCE is the City of San José's CCA program, which the San José Energy Department administers. CalCCA and CCAs individually advocate for their customers and their local energy programs before the Commission.

CCA customers receive generation services from their local CCA, and receive transmission, distribution, billing, and other services from the incumbent investor-owned

utility (IOU). While CCA and other unbundled customers do not pay PG&E's bundled generation rates, CCA customers are PG&E customers, subject to PG&E's distribution rates, several non-bypassable charges, and various utility service fees.

Q: What is the purpose of your testimony?

A: This testimony responds to PG&E's Stop-Gap Interim Real-Time Pricing (RTP) Pilots Extension proposal, which PG&E served on June 8, 2026, as Exhibit (PG&E-6) in the Dynamic Rate Options track of this proceeding (Stop-Gap Proposal).[2] PG&E's Stop-Gap Proposal asks the Commission to extend PG&E's existing Hourly Flex Pricing (HFP) pilots through 2028, to replace them with a redesigned "HFP 2.0" pilot from January 2029 through 2031, and to authorize approximately $26.5 million in incremental funding to do so.

My testimony addresses three sets of issues: (1) PG&E's proposal to discontinue the CCA incentive; (2) PG&E's proposal to replace the subscription feature of the HFP rate with a Revenue Neutral Adder (RNA); and (3) PG&E's cost recovery and cost allocation proposals, including its request for authority to update its cost estimates through a post-decision Tier 2 Advice Letter.

Q: Why do these issues matter to CalCCA and its member CCAs?

A: PG&E described CCAs in its testimony as "key partners" in ensuring that CCA customers can access the HFP rate.[3] CCAs serve approximately half of the load in PG&E's service area, with nine CCAs currently participating in PG&E's RTP pilots, and PG&E acknowledges that CCA engagement "has been important for recruiting customers and enabling load response."[4] Under the pilots, CCAs coordinate with PG&E to approve eligible customer enrollment, coordinate with PG&E to prevent double compensation, and are responsible for providing and funding the RTP generation credit for their customers.[5] Additionally, CCA customers are required to pay PG&E's distribution rates, which recover, among other things, the distribution-component shadow bill shortfalls of the HFP

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[2] *See* Exh. PG&E-6 at 2-14:7-12 and n.22 (citing the Administrative Law Judge's Ruling Setting Schedule for the Dynamic Rate Options Track (Jan. 7, 2026), p. 3).

[3] *Id*. at 2-4:4-6; *id*. at 2-35:14-18.

[4] *Id*. at 2-4:2-4; *id*. at 2-5 (Table 2-2).

[5] *Id*. at 2-9:21-22; *id*. at 5-7:32 to 5-8:3; Attachment KJC-2 (PG&E Response to CalCCA DR 8.25).

and, under Decision (D.) 24-01-032, PG&E's HFP implementation costs.[6] The design and funding decisions the Commission makes in this proceeding will therefore directly affect CCAs' operating costs for the programs, the potential costs and benefits that will accrue to CCA customers, and CCA customers' access to dynamic rates and program offerings.

Q: Please summarize PG&E's Stop-Gap Proposal.

A: PG&E proposes to extend the current HFP pilots in their existing form through 2028 if needed, and then, beginning January 1, 2029 (or sooner if feasible), to offer HFP 2.0 through 2031.[7] Among other changes, HFP 2.0 would: (1) move from a "credit-only" to a "credit-and-charge" billing structure; (2) remove subscriptions and peak demand charges and instead recover non-marginal costs through an RNA; (3) remove transactive pricing; (4) add an automatic "exit ramp" customer protection; (5) replace the current Automation Service Provider (ASP) incentive structure with a contract model targeting five to six selected ASPs; and (6) expand rate eligibility.[8]

PG&E requests $26.5 million in incremental funding through the first quarter of 2031 ($29.2 million including $2.7 million in unused funds carried over from the current pilots), sized to serve up to 16,000 enrolled service agreements, compared with 2,352 service agreements enrolled as of April 30, 2026.[9] PG&E also proposes to discontinue the CCA incentive that supports CCA participation in the current pilots, and requests authority to file a Tier 2 Advice Letter within 45 days of a final decision to update its cost estimates.[10]

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

A: CalCCA's recommendations by topic, issue, and recommended resolution are summarized in the table below:

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[6] Exh. PG&E-6 at 8-1:27 to 8-2:21; *id*. at 8-3:3-15; Attachment KJC-2 (PG&E Response to CalCCA DR 8.05).

[7] Exh. PG&E-6 at 2-14:13 to 2-15:9.

[8] *Id*. at 2-41 to 2-42 (Table 2-9); *id*. at 3-4:4-14; *id*. at 3-5:18 to 3-6:20; *id*. at 2-27:1-22.

[9] *Id*. at 2-36:17 to 2-37:7; *id*. at 2-37:34 to 2-38:2; *id*. at 2-4 (Table 2-1); *id*. at 2-39 (Table 2-8).

[10] *Id*. at 2-35:19-24; *id*. at 2-37:10-15.

Topic	Issue	Recommended Resolution
CCA Incentive Funding	PG&E proposes to discontinue the CCA incentive. PG&E: (1) performed no analysis of how eliminating the incentive would affect CCA recruitment or load response; (2) did not consult CCAs on the proposed change; (3) disregarded the Commission's stated purpose for the incentive, which was to increase enrollment; and (4) proposes to fund ASPs and its own CCA-related administration while cutting off CCAs.	- Reject PG&E's proposal. - Direct PG&E to extend funding for CCA participation in the HFP pilots, including any HFP 1.0 extension and HFP 2.0, on the terms adopted in D.24-01-032: $20 per kW-yr of enrollment in the CCA's service territory, subject to a per-pilot cap no lower than $1,800,000.
HFP Rate Design: RNA vs. Subscriptions	PG&E proposes to replace subscriptions with the RNA, but: (1) performed no sensitivity or cost-shift analysis of the RNA; and (2) admits the RNA does not ensure customer-level revenue neutrality.	- Decline to approve the RNA at this time. - Adopt PG&E's proposal for credit-and-charge billing while maintaining the existing HFP subscription design. - Permit PG&E to propose targeted, incremental refinements to the design based on the final HFP 1.0 evaluation and the RTP Impact Assessment, with an opportunity for CCAs and other stakeholders to review and comment before any change is implemented. - Direct PG&E to submit a customer education plan developed in consultation with CCAs and ASPs and authorize PG&E to reallocate funds within its approved implementation budget to support it.

Topic	Issue	Recommended Resolution
RNA Conditions (Alternative, if RNA Is Adopted)	Several aspects of the RNA proposal remain underdeveloped and unsupported: (1) the RNA proposal lacks supporting cost-incidence analysis, LSE-level reporting, and documentation of CCA customization options; (2) it is unclear under PG&E's proposal how the exit ramp would apply to CCA customers; and (3) PG&E's proposal lacks sufficient protections to limit cost shifting to non-participating customers.	If the Commission declines to adopt CalCCA's primary recommendation regarding retaining the subscription model, it should adopt the following recommendations to improve PG&E's RNA proposal: - Before HFP 2.0 is implemented, the Commission should require PG&E to serve: (1) a quantitative analysis of the RNA's customer-level, class-level, and participant/non-participant cost incidence, including the distribution of resulting credits and charges among customers within each rate schedule; (2) the results of its research on a fixed monthly charge alternative, together with a schedule for completing it; and (3) a commitment to report RNA outcomes by LSE. - Confirm that CCAs retain the ability to modify RNA values for their own customers, and that PG&E will provide itemized estimates of the costs CCAs would bear under each customization option. - Require PG&E to document the CCA customization options in its implementing advice letter or in supplemental testimony. - Require PG&E to clarify, in supplemental testimony, how the exit ramp would apply to CCA customers. - Direct PG&E to preserve subscriptions as an optional feature, as PG&E itself says it may consider after HFP 2.0. - Require, as a condition to enroll in the HFP, that all non-residential accounts either be served by an automation technology or participate with an automation service provider to limit cost shifts to non-participating customers. - Direct PG&E to submit a customer education plan developed in consultation with CCAs and ASPs and authorize PG&E to reallocate funds within its approved implementation budget to support it.
Memorandum Account Cost Recovery	Implementation costs recorded in the Dynamic and Real-Time Pricing Memorandum Account are not itemized, and some may be attributable solely to bundled generation service.	Direct PG&E to supplement its testimony to itemize the implementation costs recorded in the memorandum account and identify any attributable solely to bundled generation service, which should be recovered from bundled customers only.
Post-Decision Cost-Update Authority	PG&E requests open-ended authority to update costs after a final decision.	Reject the request unless the Commission requires bounding cost estimates before a final decision and adopts the guardrails described in this testimony.
Program Administration Forecast	PG&E's program administration forecast is not supported by actual staffing and cost detail.	Require PG&E to support its program administration forecast with actual staffing and cost detail as a condition of recovery.

Topic	Issue	Recommended Resolution
CCA Data Exchange / Double Compensation	No defined framework exists for exchanging CCA program data used to prevent double compensation.	- Review the dual enrollment check process to ensure PG&E is adhering to its own stated processes to prevent dual compensation. - Direct PG&E to convene a stakeholder process with CCAs to define the data, frequency, and confidentiality protections for any exchange of CCA program data used to prevent double compensation.

Q: How is the remainder of your testimony organized?

A: Section II addresses the CCA incentive issue. Section III addresses CalCCA's recommendation that the Commission reject PG&E's proposal to transition from subscriptions to the RNA, including the related issue of customer education. Section IV discusses the changes the Commission should require if it decides to authorize PG&E's proposal to transition to the RNA model. Section V addresses cost recovery, cost allocation, PG&E's program administration forecast, and PG&E's request for post-decision cost-update authority. Section VI addresses issues related to data exchange and prevention of double compensation. My testimony relies on PG&E's responses to CalCCA's Data Requests 8, 9 and 10, which are provided in **Attachment KJC-2**.

II. THE COMMISSION SHOULD REJECT PG&E'S PROPOSAL TO DISCONTINUE THE CCA INCENTIVE

A. PG&E's Proposal Rests on an Inference About CCA Motivation, Not on Any Analysis of the Incentive's Effect

Q: How has the CCA incentive functioned in the HFP pilots to date?

A: The Commission authorized funding for PG&E to administer each of the expanded pilots and, in place of funding for CCAs to administer pilots, adopted an incentive for CCAs that participate.[11] CCAs other than Valley Clean Energy (VCE) receive "an incentive of $20 per kilowatt for each year (kW-yr) of customer enrollment" in the PG&E Ag Pilot or PG&E Expanded Pilot 2 in their service territory, subject to a $1,800,000 cap for all CCA

[11] D.24-01-032 at 28-29; *id*., Finding of Fact 8.

incentives in each pilot.[12] The incentive is paid once per 12-month period, prorated, based on the aggregate kilowatts enrolled in the pilot in the CCA's service area.[13]

Q: Why did the Commission adopt the CCA incentive?

A: To increase enrollment. The Commission explained that, while it expected PG&E's role as administrator to expedite the pilots and avoid duplicating system costs, it also wanted "to provide CCAs with an incentive to participate in the pilots to increase the potential for reaching the expanded pilots' enrollment targets."[14] Those targets are 50 MW of enrollment in each of the two PG&E pilots, with a minimum of 10 MW.[15] Because CCAs receive a per-kW enrollment incentive rather than cost recovery for Load Serving Entity (LSE) specific administrative costs, the Commission agreed that no additional contracting requirements were needed for them.[16] The incentive is therefore tied to what CCAs deliver—enrolled load that may provide load flexibility in response to HFP price signals—and not to any particular CCA costs.

Q: What is PG&E proposing regarding the CCA incentive for HFP 2.0?

A: PG&E states that it "does not propose funding for continuation of CCA incentives as part of this Stop Gap Proposal."[17] The primary reason PG&E provides for eliminating the incentive is that CCAs "are now leveraging participation in PG&E's RTP pilots to meet LMS guidance."[18] PG&E seems to imply that this means the CCA incentive is no longer needed because Load Management Standards (LMS) requirements are incentive enough.

Q: Did PG&E analyze how eliminating the incentive would affect CCA participation?

A: No. PG&E has not analyzed how eliminating the CCA incentive would affect CCA participation, customer recruitment, load response, or enrollment outcomes. PG&E confirms that it performed no quantitative assessment of the effect on CCA recruitment activity or resulting load response and developed no forecast of resulting changes in

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[12] *Id*. at 29 & n.52; *id*., Conclusions of Law 12(h) and 13(f). The cap equals $20 per kW multiplied by 30 MW and three years. *Id*. at 29 n.52. The Commission applied the same incentive to the SCE Expanded Pilot. *Id*. at 46-47.

[13] *Id*., Attachment A, Table A-1 n.1.

[14] D.24-01-032 at 28-29.

[15] *Id*., Ordering Paragraph 1; *id*., Finding of Fact 6.

[16] *Id*. at 73.

[17] Exh. PG&E-6 at 2-35:19-20.

[18] *Id*. at 2-35:19 to 2-36:10.

customer participation or load response.[19] Instead, PG&E bases its conclusion on its review of CCAs' publicly filed LMS compliance plans and their current participation levels in the pilots.[20] PG&E confirms that its testimony identifies no separate quantitative study of whether eliminating CCA incentive funding would affect CCA participation, recruitment, or load response.[21]

Q: Did PG&E consult with CCAs before proposing to discontinue the incentive?

A: No. PG&E did not seek input from participating CCAs before proposing to eliminate the CCA incentive. It made that determination based on the LMS and CCAs' compliance plans.[22] Instead, PG&E noted that it "anticipates and looks forward to the CCAs input through the regulatory stakeholder process," which is to say, only after the proposal was filed.[23] In response to a separate request about the RNA, PG&E separately reports sharing Stop-Gap rate-design information with participating CCAs at a March 26, 2026, coordination meeting. [24] That discussion did not address the incentive, and PG&E confirms that it did not solicit CCA input on its proposed elimination. [25]

Q: Does PG&E's assumption about the impact of LMS requirements justify its proposed elimination of the CCA incentive?

A: No. PG&E's reasoning conflates two different questions. The LMS compliance plans show the pathway that some CCAs have chosen to make an hourly dynamic rate available to their customers. CCAs stating their participation in the pilot in their LMS plans is not evidence of what would happen to unbundled customer recruitment, outreach, and load response if the funding that supports that work was withdrawn. PG&E concedes it never studied the second question.[26]

The distinction matters because the purposes of the pilots are not served by merely having a dynamic rate pilot available. PG&E itself tells the Commission that CCA

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[19] Attachment KJC-2 (PG&E Response to CalCCA DR 8.01(b)); *see also id*. (PG&E Response to CalCCA DR 8.01(a)).
[20] *Id*. (PG&E Response to CalCCA DR 8.04).
[21] *Id*. (PG&E Response to CalCCA DR 8.02).
[22] *Id*. (PG&E Response to CalCCA DR 8.04).
[23] *Id*.
[24] *Id*. (PG&E Response to CalCCA DR 8.13).
[25] *Id*. (PG&E Response to CalCCA DR 8.04).
[26] *Id*. (PG&E Responses to CalCCA DRs 8.01 and 8.02).

engagement "has been important for recruiting customers and enabling load response."[27] Recruiting customers and enabling load response requires outreach, enrollment coordination, dual-participation verification, and tracking of billing and credit processing, all of which have associated costs for CCAs and impact the cost effectiveness of participation in HFP 2.0. The LMS obligation PG&E describes is to offer customers the option to enroll in a dynamic rate by July 1, 2027, if approved by the CCA's rate-making authority, or a program in which the customer can respond to marginal cost signals.[28] Nothing in the LMS regulation requires CCAs to participate in PG&E's HFP pilot specifically. If material changes are made to the pilot that make a CCA's continued participation in the pilot untenable, then a CCA may choose to no longer participate.

Furthermore, the LMS obligation does not require a CCA to recruit customers into a rate or program option, conduct outreach, or provide ongoing support. Nor does the obligation necessitate CCAs absorbing the costs of enrollment coordination, data exchange, or generation-credit processing to support unbundled customer participation in the pilots. Accordingly, it is unreasonable for PG&E to assume that CCAs' LMS obligations will necessarily lead to customer recruitment and ongoing enrolled customer support, absent the monetary incentives that have enabled CCAs to conduct those tasks.

Q: PG&E notes that the Commission's decision refers to CalCCA's LMS argument. Does that show the incentive was tied to LMS compliance?

A: No. PG&E observes that D.24-01-032 notes CalCCA's argument that administering pilots would help CCAs gain experience ahead of the LMS deadlines, and infers that the availability of funding is connected to the LMS.[29] But that argument appears in the decision's summary of CalCCA's position on funding CCAs to administer pilots, which the Commission did not adopt in that form.[30] The Commission's own stated reason for adopting the incentive was the enrollment targets.[31] I did not find in the decision any

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27 Exh. PG&E-6 at 2-4:2-4.
28 *Id*. at 2-36:1-3.
29 Attachment KJC-2 (PG&E Response to CalCCA DR 8.04).
30 D.24-01-032 at 28.
31 *Id*. at 28-29.

condition tying the incentive to a CCA's LMS compliance, or any provision ending the incentive once a CCA has an approved compliance plan.

Q: Has the CCA incentive been successful in increasing enrollment in the PG&E HFP?

A: Yes, it has. As of October 21, 2026, the CCA customers account for 817 enrolled service agreements between HFP Pilot 1 and HFP Pilot 2.[32] There are 50 customers in HFP Pilot 1 with an enrolled load of 6.86 MW, and 767 customers in HFP Pilot 2 with an enrolled load of 48.68 MW.[33] CCA customers make up approximately 7%[34] of the enrolled load in HFP Pilot 1 and approximately 81% of the enrolled load in HFP Pilot 2.[35]

B. PG&E's Other Justifications for Eliminating the CCA Incentive Are Similarly Unconvincing and Unsupported

Q: What other justifications does PG&E offer for eliminating the CCA incentive?

A: PG&E states that CCAs are responsible for their own procurement costs and for how they reflect those costs in their generation rates.[36] PG&E notes that CCAs rely on PG&E's pricing and billing infrastructure, "for which CCAs are not charged."[37]

Q: Is PG&E's statement that CCAs are responsible for their own procurement costs relevant?

A: No. The CCA incentive was not adopted to fund procurement. The Commission adopted it as a per-kW enrollment incentive.[38] As PG&E's own reference to D.24-01-032 shows, CalCCA asked for funding "to administer dynamic rates pilots."[39] The costs CCAs incur to earn the incentive are operational: coordinating enrollment approvals; verifying and preventing dual participation through a recurring file exchange with PG&E in which CCAs are asked to respond within two to five business days; receiving price data; funding and processing the generation credit for unbundled customers; and customer-facing outreach.[40]

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32 Attachment KJC-2 (PG&E Response to CalCCA DR 10.01).

33 *Id*.

34 (6.86 / 99.89 = 7% (rounded)).

35 (48.68 / 60.43 = 81% (rounded)).

36 Exh. PG&E-6 at 2-35:19 to 2-36:10. PG&E also notes that, under credit-and-charge billing, CCAs "will be less exposed to funding shortfalls" from the annual True-Up process. *Id*. at 2-36:11-15.

37 *Id*. at 2-35:19 to 2-36:10.

38 D.24-01-032 at 28-29.

39 Attachment KJC-2 (PG&E Response to CalCCA DR 8.04).

40 Exh. PG&E-6 at 2-9:21-22; *id*. at 5-6:25-30; *id*. at 5-7:32 to 5-8:3; Attachment KJC-2 (PG&E Response to CalCCA DR 8.25).

PG&E's observation that CCAs bear their own procurement costs is irrelevant; the incentive does not go toward procurement costs, it goes toward operational costs associated with program enrollment work.

Q: PG&E notes that CCAs use its pricing and billing infrastructure at no charge. Does that justify eliminating the incentive?

A: No. First, PG&E's assertion that CCAs use the pricing and billing infrastructure at no charge is misleading; *all* ratepayers, including CCA customers, fund the pricing and billing infrastructure. Second, access to PG&E's pricing and billing infrastructure is a feature of the pilot design, and the only available pathway to implementing the pilots—not a favor to CCAs. It is how CCA customers are priced and shadow billed under the pilot, and the infrastructure is funded by all ratepayers.

Furthermore, CCAs currently use PG&E's generation prices rather than their own because the billing system cannot support customized generation prices.[41] The availability of this shared infrastructure, paid for by all ratepayers through distribution rates, does not eliminate the CCA-side costs I described above, and it is not a substitute for funding them. Additionally, without a CCA incentive, CCA customers would effectively be paying twice for their CCA to participate: once through distribution rates, and then again through their generation rate. The CCA generation rate would be impacted by the operational costs incurred by the CCAs to support enrollment.

Q: PG&E also points to the credit-and-charge billing structure. Does that change your view?

A: No. CalCCA agrees that credit-and-charge billing is a meaningful improvement and supports modifying the pilots so that there is credit-and-charge billing. PG&E itself recognizes that credits without offsetting charges raise a concern for "PG&E, CCAs, and stakeholders" about cost shifts to non-participants.[42] However, reducing exposure to generation credit shortfalls is a different matter from compensating CCAs for the operational costs of participating. Credit-and-charge billing does nothing to reduce those

[41] Exh. PG&E-6 at 5-6 n.3.
[42] *Id*. at 2-20:13-19.

costs. And, as discussed in Section III, the proposed RNA leaves CCAs exposed to a different category of generation-credit risk that PG&E has not analyzed.

C. Eliminating the CCA Incentive Is Inconsistent with PG&E's Own Funding Requests and Would Jeopardize the Pilots' Objectives

Q: Is PG&E's proposal to eliminate the CCA incentive consistent with the rest of its funding request?

A: It is not. PG&E asks the Commission to approve $14.8 million for program administration and customer support, and $8.2 million for pricing, billing, and customer relationship management systems.[43] PG&E's program administration request includes staff who "support incentive processing for ASPs and CCAs" and program managers who coordinate with CCAs.[44] PG&E's response to CalCCA's data request confirms that the budget funds "coordination with CCA and ASP partners."[45] In other words, PG&E asks ratepayers to fund PG&E's side of the coordination with CCAs while proposing to cut off funding for the CCAs' side of the coordination, which supports enrolled customers and encourages further new enrollment.[46]

PG&E's treatment of ASPs is even more difficult to reconcile. PG&E explains that many ASPs have indicated that the current ASP incentive "does not appropriately compensate for their internal pilot start-up costs and ongoing support efforts."[47] PG&E's response in this case is to propose contracts with five to six selected ASPs that would pay each a fixed annual program management fee plus variable milestone-based payments, supported by a $3.6 million ASP budget that combines approximately $2.6 million in unused funds from the existing ASP budget with $1 million in new money.[48] PG&E would step the compensation down over time as ASPs develop their business models.[49]

PG&E has therefore concluded that third parties who recruit customers and enable load response need start-up and ongoing administrative support, and that the right response

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43 *Id*. at 2-39 (Table 2-8, lines 1-2, column (d)).
44 *Id*. at 5-10:19-20; *id*. at 5-11:19-26.
45 Attachment KJC-2 (PG&E Response to CalCCA DR 8.19).
46 D.24-01-032 at 28-29.
47 Exh. PG&E-6 at 2-26:28-31.
48 *Id*. at 2-27:15-31; *id*. at 5-12:26 to 5-13:4; *id*. at 2-39 (Table 2-8, line 3).
49 *Id*. at 2-27:33 to 2-28:3; *id*. at 5-13:8-16.

is incremental supportive funding, even though a large part of the original ASP budget of approximately $2.6 million remained unused. CCAs perform the same recruiting that PG&E credits as "important," and incur comparable ongoing operational costs.

Q: Does PG&E's proposal create a cost-shift concern for unbundled customers?

A: Yes. Unbundled customers will pay, through distribution rates, for the distribution-component shadow bill shortfall that PG&E proposes to recover through its Distribution Revenue Adjustment Mechanism (DRAM) balancing account. However, PG&E is proposing to remove the ratepayer-funded CCA incentive.[50] PG&E's implementation costs of roughly $26.5 million are to be tracked in the DRTPMA and recovered in a future general rate case, and under D.24-01-032, recovered from all bundled and unbundled customers.[51] If CCAs are not compensated for the operational costs of participating, unbundled customers risk paying for the administration of a program in which their access is constrained, because the CCAs that enable that access cannot fund the work. That outcome is neither equitable nor consistent with the Commission's interest in supporting broad access to dynamic rates. Additionally, the customers of CCAs who continue to choose to participate in the pilots will be forced to pay for costs twice—once through their CCA's generation rates, and once through PG&E distribution rates as described above.

Q: Does PG&E's proposed expansion of the pilot heighten your concern?

A: Yes. PG&E has sized HFP 2.0 to serve up to 16,000 enrolled service agreements, nearly seven times the 2,352 service agreements enrolled today.[52] PG&E's testimony does not disclose how many of the currently enrolled service agreements belong to CCA customers; Table 2-1 breaks enrollment out by sector only, not by LSE. Nor does PG&E say how many of the roughly 13,600 additional service agreements it expects to come from CCA customers. CCAs serve about half of PG&E's load. If the Commission's goal is to substantially expand participation, it makes little sense to eliminate funding for the entities that serve half of the potential participants, particularly when PG&E has not studied what would happen if it did.

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[50] *Id*. at 8-2:9-16; Attachment KJC-2 (PG&E Response to CalCCA DR 8.05(a)).

[51] Exh. PG&E-6 at 8-3:10-15; Attachment KJC-2 (PG&E Response to CalCCA DR 8.05(b)); D.24-01-032 at 55-56. I address cost recovery in Section V.

[52] Exh. PG&E-6 at 2-37:34 to 2-38:2; *id*. at 2-4 (Table 2-1).

D. Recommendation Regarding the CCA Incentive

Q: What do you recommend regarding the CCA incentive?

A: I recommend that the Commission reject PG&E's proposal to discontinue the CCA incentive and instead order continued funding of the CCA incentive, through any HFP 1.0 extension and through HFP 2.0, on the terms the Commission adopted in D.24-01-032: $20 per kW-yr of enrollment in the CCA's service territory, subject to a per-pilot cap no lower than $1,800,000. The CCA incentive should remain available to every CCA that elects to participate. The pilots authorized in D.24-01-032 conclude on December 31, 2027,[53] so the incentive adopted there expires with them. CalCCA asks the Commission to extend the same incentive for the extension period.

The Commission should also require PG&E to track and report enrollment and load response by LSE in its Measurement and Evaluation reports so stakeholders can continue to have insight into bundled versus unbundled customer participation to inform any future modifications to the program.

III. THE COMMISSION SHOULD NOT ADOPT PG&E'S PROPOSAL TO REPLACE THE SUBSCRIPTION WITH THE RNA AT THIS TIME

A. Background on PG&E's Proposal

Q: What is PG&E proposing regarding subscriptions?

A: Under the current HFP design, customers are assigned a subscription: a predefined load profile, based on the customer's own historical usage or a class average, that is charged at the customer's otherwise applicable tariff (OAT). Only deviations from that profile are charged or credited at the dynamic hourly price.[54] PG&E proposes to eliminate subscriptions for HFP 2.0 and to recover non-marginal costs through an RNA, which PG&E describes as a dollars-per-kilowatt-hour charge that will "make the dynamic rate revenue neutral to the retail OAT rate" and will vary by rate schedule and, for some schedules, by time-of-use period.[55] PG&E also proposes to remove peak demand charges,

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53 D.24-01-032 at 2.

54 Exh. PG&E-6 at 2-20:21 to 2-21:10; *id*. at 3-3 (Table 3-1, line 6).

55 *Id*. at 2-25:6-15; *id*. at 3-3 to 3-4:14.

on the premise that all usage will be subject to the dynamic rate.[56] PG&E describes the result as a "price you see is the price you pay" design.[57]

Q: Why does PG&E say subscriptions should be removed?

A: PG&E's reasons center on customer experience. PG&E reports that it has "received considerable feedback from customers that they find subscriptions challenging to understand and manage"; that subscription scaling can muddle the price signal; that subscriptions add implementation cost and complexity for PG&E, customers, and ASPs; and that they complicate measurement and evaluation.[58] PG&E also observes that a subscription set too low "can result in customers achieving bill savings without changing load patterns," and that, in the VCE AgFIT pilot, customers with highly variable usage were "often underpaying or overpaying for electricity, relative to their cost of service."[59]

Q: Does CalCCA support any of these changes PG&E proposes for HFP 2.0?

A: Yes. CalCCA supports PG&E's proposed move from a credit-only to a credit-and-charge billing structure. As PG&E explains, that change would eliminate the bill protection inherent in the current design, give customers a stronger incentive to respond to the HFP rate, and "mitigate the concern for PG&E, CCAs, and stakeholders that credits to customers without the offsetting charges could create cost shifts to non-participating customers."[60] CCAs support improving the incentive provided to customers to shift behavior by adding the "charge" component to the pilot, and I believe the credit-and-charge change addresses a substantial portion of the cost-shift and load-response concerns PG&E identifies. It also would mean that customers who are structural winners today would not be able to count on credits continuing without any shifting of their load; they would bear the risk of net charges at True-Up if their usage or the price environment changes, so they, too, would have an incentive to continue to monitor and respond to the price signal. As I explain below, that is why the more complicated elements of PG&E's proposal, particularly the RNA, are unnecessary at this stage.

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56 *Id*. at 3-4:4-14.
57 *Id*. at 2-25:10-12.
58 *Id*. at 2-20:22-24; *id*. at 2-24:4 to 2-25:5; *id*. at 3-3:6-9.
59 *Id*. at 2-23:13-15; *id*. at 2-24:2-3.
60 *Id*. at 2-19:18 to 2-20:19.

B. The RNA Is Underdeveloped and Untested

Q: What analysis has PG&E performed of the RNA's effects?

A: The RNA is the mechanism by which PG&E proposes to recover the non-marginal costs that, under HFP 1.0, are recovered through the subscription and through peak demand charges. Such an important mechanism should not be adopted, even on a pilot basis, without at least a basic quantitative understanding of who pays and who benefits.

PG&E failed to conduct any such analysis. PG&E did not conduct any sensitivity analyses showing the range of RNA values across rate schedules,[61] and it did not conduct any testing to determine if the RNA eliminates or minimizes cost shifting among customer classes or between participating and non-participating customers.[62] PG&E likewise did not estimate the customer-level impacts of continuing the current design compared with moving sooner to a corrective design, objecting that preparing such an estimate "would be burdensome and speculative."[63]

Q: Does the RNA ensure revenue neutrality for individual customers?

A: No, and PG&E admits this. PG&E did not design the RNA to achieve revenue neutrality for individual customers. PG&E calculates the RNA to achieve revenue neutrality only across each rate schedule.[64] PG&E acknowledges that the RNA can provide credits for an incidentally favorable load shape, and it justifies those credits on the ground that such customers use energy when it costs the least and create value for the utility.[65]

That feature undercuts PG&E's rationale for replacing subscriptions. PG&E identifies "structural winners"—customers who receive credits without changing their load patterns—as a defect in the current design. PG&E also criticizes subscriptions that are set too low because they can allow customers to achieve bill savings without changing load.[66] Yet PG&E's proposed RNA permits the same outcome: customers can receive bill benefits based on their pre-existing load shapes rather than on their responsiveness to HFP prices.

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61 Attachment KJC-2 (PG&E Response to CalCCA DR 8.10(a)-(b)).

62 *Id*.

63 *Id*. (PG&E Response to CalCCA DR 8.24(c)).

64 Exh. PG&E-6 at 3-4:6-10.

65 Attachment KJC-2 (PG&E Response to CalCCA DR 8.09(a); PG&E Response to CalCCA DR 8.22).

66 Exh. PG&E-6 at 2-19:15-17; *id*. at 2-24:2-3.

Thus PG&E's proposed change in pilot design does not eliminate the problem it identifies; rather, it just shifts the problem from one that presents at an individual customer subscription level to one that presents at the schedule-wide cost recovery level.

PG&E would replace customer-specific subscriptions and demand charges with a volumetric per-kWh adder. That change reallocates non-marginal costs among customers within each rate schedule and generally shifts more recovery to customers with higher load factors and less recovery to customers with lower load factors. PG&E has not quantified the potential size of those shifts, identified the customers who would bear them, or evaluated the likely distribution among customers within a schedule.

Q: How does the RNA interact with PG&E's proposal to remove peak demand charges?

A: PG&E again offers assurance only at the schedule level. PG&E removes peak demand charges on the premise that all usage will be subject to a dynamic rate that already reflects capacity costs.[67] PG&E maintains that the dynamic rate "collects the same capacity costs as peak demand charges typically collect" and uses the RNA to capture any difference between the HFP and TOU designs so that the schedule does not over- or under-collect.[68] PG&E therefore proposes that the appropriate capacity cost levels will be recovered only at the rate schedule level as a whole.

PG&E does not show that the new design produces appropriate outcomes for individual customers. Under existing tariffs, demand charges generally assign costs based on each customer's own peak demand. HFP 2.0 would instead recover those costs through a volumetric per-kWh adder and dynamic capacity prices. That change can produce materially different results for customers whose cost causation turns on their individual peak demand, including large commercial and industrial customers.

PG&E has not quantified those customer-level results. It has not identified which customers would pay more or less under the replacement design, evaluated whether the RNA over- or under-recovers from individual customers relative to cost of service, or

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67 *Id*. at 3-4:12-14.

68 Attachment KJC-2 (PG&E Response to CalCCA DR 8.11).

performed RNA calculations beyond the workpapers it submitted.[69] Schedule-level revenue neutrality therefore does not establish customer-level cost causation.

Q: Why does this matter specifically to CCAs?

A: Under the HFP design, the CCA, not PG&E, is responsible for providing the RTP generation credit to its unbundled customers.[70] By contrast, PG&E's bundled customers fund the generation-component shortfall for PG&E's bundled participants through the Energy Resource Recovery Account (ERRA).[71] If the RNA allows customers with favorable load shapes to receive generation credits without changing their behavior, CCAs involved in the HFP will be required to fund those credits for their own customers, with no analysis available to inform them of the magnitude of their exposure.

If CCAs cannot reasonably estimate their total participation costs, inclusive of the value of credits they will be expected to pay customers, and whether those credits will be going to compensate load shifting or a redistribution of costs amongst customers, CCA participation may ultimately be impacted, as CCA governing boards must weigh the costs, benefits, and risks of participation before approval.[72]

Q: PG&E says HFP is more cost-based than time-of-use rates. Does that claim help address these concerns?

A: No. PG&E acknowledges that the RNA, the "price you see is the price you pay" design, and dynamic rates in general "cannot prevent all cost shifts."[73] Its response is a comparative argument: because TOU customers already create a cost shift, and because HFP is more cost-based than TOU, HFP customers are "effectively reducing an existing cost shift rather than creating a new one, even if they are receiving bill benefits without a change in behavior."[74]

This reasoning is not a substitute for analysis. That one rate design is imperfect does not establish that its replacement minimizes cost shifting; the question is the size and direction of the remaining shift under the proposed design, and PG&E has confirmed it has

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69 *Id*. (PG&E Response to CalCCA DR 8.10(a)).
70 Exh. PG&E-6 at 5-7:32 to 5-8:3.
71 *Id*. at 8-2:15-16; Attachment KJC-2 (PG&E Response to CalCCA DR 8.05(a)).
72 Attachment KJC-2 (PG&E Response to CalCCA DR 8.27(a)).
73 *Id*. (PG&E Response to CalCCA DR 8.09(b)).
74 *Id*.; *see also id*. (PG&E Response to CalCCA DR 8.06) (nearly identical language).

not tested it.[75] PG&E characterizes the distribution component of shadow-bill credits as a "revenue shortfall" and proposes to recover that shortfall from bundled and unbundled customers through DRAM.[76] PG&E cannot both ask the Commission to approve recovery of a shortfall from unbundled customers and deny that a shortfall exists when asked to quantify it. Notably, PG&E treats cost shifts to non-participants as a genuine concern when it supports credit-and-charge billing but dismisses them as a comparative matter when defending the RNA.[77]

Q: Has PG&E shown that removing subscriptions will improve cost accuracy?

A: No. PG&E does not justify removing subscriptions on cost-accuracy grounds. PG&E states that both the current subscription design and its proposed replacement are close to PG&E's cost of service and that neither design is superior for that purpose. PG&E instead seeks to remove subscriptions to improve customer experience.[78] While customer experience is a critical consideration, that rationale does not support replacing a known, if imperfect, design with an untested design that creates different and unquantified customer impacts. PG&E has not shown that the RNA improves cost accuracy, reduces cost shifts, or produces more equitable outcomes than subscriptions. PG&E identifies customer comprehension as the principal problem with subscriptions, but it can address that problem through clearer customer education and targeted refinements rather than a wholesale rate redesign.

C. PG&E Did Not Meaningfully Evaluate Alternatives to the RNA

Q: Did PG&E evaluate a modified subscription as an alternative to full removal?

A: Not in any rigorous way. PG&E considered the role of subscriptions but did not evaluate a modified subscription design. PG&E did not test alternatives such as more frequent subscription updates or a shorter true-up period, and it offered no analysis showing that those changes would fail to address the underlying concerns.[79] PG&E also acknowledges that the current and proposed designs offer comparable cost accuracy.[80] A modified

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75 *Id*. (PG&E Response to CalCCA DR 8.10(b)).
76 Exh. PG&E-6 at 8-1:27 to 8-2:21; Attachment KJC-2 (PG&E Response to CalCCA DR 8.05(a)).
77 Exh. PG&E-6 at 2-20:15-19.
78 Attachment KJC-2 (PG&E Response to CalCCA DR 8.24(c)).
79 *Id*. (PG&E Response to CalCCA DR 8.21).
80 *Id*. (PG&E Response to CalCCA DR 8.24(c)).

subscription therefore presents a practical middle option: it could address customer comprehension and administrative complexity without replacing the current design with an untested RNA. PG&E did not test that option.

Q: Did PG&E consider any alternatives to the RNA for collecting non-marginal costs?

A: No, PG&E did not evaluate alternatives to the RNA.[81] PG&E indicated in discovery that it is in the process of researching a fixed monthly charge that could reduce or eliminate the RNA, but noted it has only begun that work and has not produced any analysis of the fixed-charge option.[82] It makes little sense to adopt a new, unanalyzed RNA design when PG&E is already exploring an alternative that might make much of it unnecessary. PG&E also acknowledges that it "may consider offering subscriptions as an optional feature after HFP 2.0"—confirming that subscriptions are not so incompatible with the program that they cannot continue to be offered while the evaluations are completed.[83]

D. Changing Many Variables at Once Will Undermine, Not Advance, the Pilots' Learning Objectives

Q: Why is it important to limit the number of changes made to the pilots at one time?

A: A pilot exists to generate evidence. Evidence is only useful if changes are introduced at a pace that allows their effects to be isolated. PG&E recognizes this principle: it proposes not to offer subscriptions as an option in HFP 2.0 specifically "to test the RNA in isolation."[84] But HFP 2.0 does not test the RNA in isolation. It simultaneously changes the billing structure to credit-and-charge, removes subscriptions, adds the RNA, removes peak demand charges, removes transactive pricing, adds an exit ramp, replaces the ASP compensation model, and adds rate eligibility.[85] If customer outcomes change, it will be impossible to determine which change or changes triggered those impacts.

Q: Does PG&E's own evidence support a more incremental approach?

A: Yes. PG&E's measurement and evaluation testimony acknowledges that the evaluation of the earlier VCE AgFIT pilot found that observed load response was constrained by, among

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81 *Id*. (PG&E Response to CalCCA DR 8.12).

82 *Id*.; *see also* Exh. PG&E-6 at 3-7:25-27 (PG&E "will also investigate the potential to increase fixed charges for HFP participants in order to reduce non-coincident demand and energy charges").

83 Exh. PG&E-6 at 3-3:9 to 3-4:3.

84 *Id*. at 3-4:1-3.

85 *Id*. at 2-41 to 2-42 (Table 2-9); *id*. at 3-4:4-14.

other things, "rate design changes during the pilot" and "the need for longer periods of stable implementation."[86] It reports that evaluation of SCE's pilot found bill impacts "often driven by structural load characteristics" rather than sustained behavioral response.[87] And it explains that, because the current HFP pilots began enrolling customers only in the fourth quarter of 2024, participants faced "the lowest and least variable prices" in 2025, which "likely dampened customers' incentive to adjust their usage behavior."[88] In short, PG&E itself acknowledges that the current pilots have had limited time and limited price variability in which to demonstrate how customers respond. Redesigning the rate before the pilots have had that opportunity risks addressing the wrong problem.

The final HFP 1.0 evaluation is due March 1, 2028, and the RTP Impact Assessment is expected by May 2028.[89] PG&E's proposal would implement HFP 2.0 in January 2029, after those studies, but would lock in the design now, before those studies are published.

Q: Can PG&E adjust the pilot design in 2028 as learnings emerge?

A: PG&E suggests it can, if regulatory approvals are timely. PG&E states that it "supports incorporating available HFP 1.0 learnings into the design and implementation of HFP 2.0," and "would consider incorporating additional HFP 1.0 learnings during 2028 if regulatory approvals for such changes were received on a timeline that enabled accelerated changes where feasible."[90] PG&E also states that its proposal "permits an earlier transition if regulatory and implementation timelines allow," but that it "cannot presently confirm that preliminary findings would support an earlier transition."[91] The more measured path would be to adopt the credit-and-charge change that both PG&E and CalCCA support, maintain the remaining features of the current design, and use the 2028 evaluation results to inform small, targeted refinements, rather than committing now to an RNA that PG&E has not analyzed.

PG&E states that it is "exploring options to accelerate implementation of HFP 2.0," but would need to request regulatory approval to do so, and that its implementation timeline

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86 *Id*. at 7-5:31 to 7-6:2.
87 *Id*. at 7-6:2-6.
88 *Id*. at 7-6:17 to 7-7:10.
89 *Id*. at 2-15:24-28; *id*. at 7-5:8-10.
90 Attachment KJC-2 (PG&E Response to CalCCA DR 8.24(e)).
91 *Id*. (PG&E Response to CalCCA DR 8.24(d)); *see also* Exh. PG&E-6 at 2-15:7-9.

"may be updated" through the post-decision advice letter.[92] In other words, PG&E has made no firm implementation acceleration proposal. CalCCA does not oppose accelerating changes it supports, such as credit-and-charge billing. But accelerating the removal of subscriptions or the adoption of the RNA before the HFP 1.0 evaluations are complete would compound the concerns I describe above. The Commission should require PG&E to identify the specific conditions under which it would accelerate, and order that any request to accelerate should proceed through a process that allows stakeholder review.

E. Customer Education, Not a New Rate Structure, Should Be the Priority

Q: How does customer education relate to PG&E's proposal?

A: PG&E's principal reason for removing subscriptions is that customers "find subscriptions challenging to understand."[93] A comprehension problem calls for better education and support. These pilots should work when participants, and the ASPs and CCAs who help them, understand the rate. Yet PG&E's marketing, education, and outreach (ME&O) request is only $175,000 over the entire four-year stop-gap period—less than one percent of the $26.5 million PG&E seeks.[94] That budget is limited to maintaining existing pilot materials, refreshing fact sheets, and sending annual support emails, with an objective of "pilot continuity."[95] By PG&E's own account, participating customers will have to "affirmatively confirm their intent to remain on the pilot (HFP 2.0)" after reviewing revised terms and conditions, and customers who do not will be unenrolled from HFP 1.0.[96] The more PG&E changes at one time, the more education customers will need, and the more likely it is that customers will drop out, undermining the very purpose of PG&E's proposed changes to the tariff.

Q: What do you recommend regarding customer education?

A: I recommend the Commission direct PG&E to submit a customer education plan, developed in consultation with CCAs and ASPs, and authorize PG&E to reallocate funds within its approved implementation budget to support it.

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92 Attachment KJC-2 (PG&E Response to CalCCA DR 8.23).
93 Exh. PG&E-6 at 2-20:22-23; *see also id*. at 3-3:6-9.
94 *Id*. at 2-39 (Table 2-8, line 6); *id*. at 6-3 (Table 6-1).
95 *Id*. at 6-1:5-7; *id*. at 6-2:3-5; *id*. at 6-3 (Table 6-1).
96 *Id*. at 5-10:33 to 5-11:5.

Q: Would education remain important if the Commission were to adopt the RNA?

A: Yes. Even if the Commission adopts the RNA, customer education will be critical. The RNA changes how customers' bills are calculated. HFP 2.0 introduces the possibility of net charges, and the exit ramp is a new feature that customers must understand. A robust education plan developed with ASPs and CCAs, who are often customers' first point of contact, will be necessary regardless of the Commission's decision on subscriptions.

F. Recommendations Regarding the Proposed Transition from Subscriptions to RNA

Q: What do you recommend regarding PG&E's proposal to replace subscriptions with the RNA?

A: I recommend that the Commission decline to approve the replacement of subscriptions with the RNA at this time. The Commission should instead:

- Approve PG&E's proposal to adopt credit-and-charge billing, but otherwise maintain the current HFP design, including subscriptions, through the extension period;
- Permit PG&E to propose targeted, incremental refinements to the design based on the final HFP 1.0 evaluation and the RTP Impact Assessment, with an opportunity for CCAs and other stakeholders to review and comment before any change is implemented; and
- Direct PG&E to submit a customer education plan, developed in consultation with CCAs and ASPs, and authorize PG&E to reallocate funds within its approved implementation budget to support it.

IV. IN THE ALTERNATIVE, IF THE COMMISSION APPROVES THE RNA, IT SHOULD REQUIRE PG&E TO PROVIDE SUPPLEMENTAL INFORMATION AND OPTIONS TO SMOOTH THE TRANSITION AND ADOPT AN AUTOMATION TECHNOLOGY REQUIREMENT FOR NON-RESIDENTIAL PARTICIPANTS

A. If the Commission Approves the RNA, It Should Require PG&E to Provide Supplemental Information and Options to Smooth the Transition

Q: If the Commission approves the transition to the RNA despite CalCCA's recommendations above, what can it do to ensure stakeholders better understand the impact of this new pilot element before implementation?

A: If the Commission nonetheless adopts the RNA, it should condition that approval on PG&E first serving, before HFP 2.0 is implemented: (1) a quantitative analysis of the RNA's

customer-level, customer-class, and participant/non-participant cost incidence, including the distribution of resulting credits and charges among customers within each rate schedule; (2) the results of its research on a fixed monthly charge alternative, together with a schedule for completing it; and (3) a commitment to report RNA outcomes by LSE. This additional information will allow stakeholders like CCAs to better understand the upcoming changes, assess their ability to participate in the new structure, and communicate to potential participants about these changes.

Q: If the Commission approves the transition to the RNA, what else can it do to help ensure CCAs have the information they need to transition to this structure?

A: The Commission should also require PG&E to confirm that CCAs will retain the ability to modify RNA values for their own customers, and to provide itemized estimates of the costs CCAs would bear under each customization option, which PG&E has said are the CCAs' responsibility.[97] Because Exhibit PG&E-6 does not describe the CCA customization options PG&E has confirmed in discovery, the Commission should also require PG&E to document them in its implementing advice letter or in supplemental testimony.

Q: If the Commission approves the transition to the RNA, what other aspects of the proposals related to the RNA should be clarified?

A: The proposed exit ramp. CalCCA does not oppose the concept of an exit ramp in the event the Commission removes the subscription, which itself acts as a customer protection. PG&E acknowledges that removing subscriptions "takes away a measure of customer protection against long periods of sustained high prices," and proposes that HFP 2.0 prices automatically revert to the OAT if day-ahead energy-plus-generation-capacity prices reach specified thresholds.[98]

However, PG&E's testimony does not explain how the exit ramp would work for CCA customers. PG&E generates a separate generation price for each LSE, including each participating CCA, and CCAs may modify their generation-side pricing parameters.[99] PG&E does not say whether the exit ramp triggers are evaluated using PG&E's generation

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97 *See* Attachment KJC-2 (PG&E Responses to CalCCA DRs 8.16 and 8.27(a)).

98 Exh. PG&E-6 at 3-5:19-20; *id*. at 3-6:4-20.

99 *Id*. at 5-6:15-17; Attachment KJC-2 (PG&E Response to CalCCA DR 8.27(a)).

prices or each CCA's generation prices. Nor does it explain who bears any resulting generation-side revenue effect for unbundled customers, since PG&E describes its recovery of exit-ramp under-collections through balancing accounts for generation for bundled customers only.[100] PG&E should clarify these points before any exit ramp is approved.

Q: What else can the Commission do to help smooth the transition to this new structure?

A: The Commission should direct PG&E to preserve subscriptions as an optional feature, as PG&E itself says it may consider after HFP 2.0.

B. If the Commission Approves the RNA, It Should Require Non-Residential Accounts to be Served by an Automation Technology or Participate with an Automation Service Provider

1. HFP Is Intended to Produce Load Shift, But Price Exposure Alone Does Not Ensure It

Q: What is the purpose of the HFP pilots?

A: PG&E describes HFP as "a performance-based overlay on top of existing rates" designed to "incent targeted load response" to variable and unpredictable hourly prices.[101] PG&E identifies the pilots' authorizing decision as the "Decision to Expand System Reliability Pilots," D.24-01-032.[102] The value of an hourly rate to the system, and to the ratepayers who fund the pilots, depends on whether customers' load actually moves out of high-priced hours.

Q: Does PG&E's RNA design ensure that customers who receive bill benefits actually change their load?

A: No. As I explained in Section III, PG&E acknowledges that under its proposed design, credits "could be given for incidentally favorable load shape," and that customers with a favorable load shape may receive bill benefits "without a change in behavior."[103] PG&E's testimony recognizes the same phenomenon in other pilots, reporting that the evaluation of SCE's Dynamic Rate Pilot found bill impacts "often driven by structural load

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100 Exh. PG&E-6 at 3-6:28 to 3-7:2.

101 *Id*. at 5-9:19-21.

102 Attachment KJC-2 (PG&E Response to CalCCA DR 8.04). *See* D.24-01-032 at 2 (the expanded pilots "are authorized to provide system reliability benefits between June 1, 2024 and December 31, 2027).

103 Attachment KJC-2 (PG&E Responses to CalCCA DRs 8.22 and 8.09(b)).

characteristics" rather than sustained behavioral response.[104] Credit-and-charge billing, which CalCCA supports, exposes customers to charges and strengthens the incentive to respond. But it does not verify that a response is occurring. A customer whose load is already favorably shaped can still earn net credits, and for unbundled customers, the generation component of those credits is funded by the CCA.[105]

This issue is more acute for non-residential customers that have much larger loads than residential customers.[106] Additionally, residential customers make up a much smaller portion of enrolled load in sum and generally have less access to technology than non-residential customers.[107]

Q: What does the record show about the role of automation in producing load response?

A: PG&E's own testimony points to the technology. PG&E states that outcomes in dynamic pricing evaluations "depend heavily on customer segment, technology enablement, billing structure, and program maturity."[108] PG&E defines ASPs as entities that "manage customer end-use devices to respond to RTP prices on the customer's behalf," and makes HFP prices available through an API and the CEC's Market-Informed Demand Automation Server to support automated load control.[109] PG&E proposes to select ASPs based on their capability to "automate load response for customers," and to pay them partly based on "demonstrated load response."[110]

PG&E already conditions eligibility for certain residential rates on technology: E-ELEC customers must have a heat pump, behind-the-meter storage, or EV charging equipment, and EV2A customers must have an EV or behind-the-meter storage.[111] The Commission took the same approach when it authorized the pilots. It expanded participation to residential, commercial, and industrial customers "with load shifting

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104 Exh. PG&E-6 at 7-6:2-6.

105 *Id*. at 5-7:32 to 5-8:3; *id*. at 8-2:9-16.

106 *Mid-Term Evaluation of PG&E's Hourly Flex Pricing Pilot* (Aug. 2026), at 2, Table ES.1 (showing megawatts (MW) of enrolled load with 102.7 MW in Agricultural, 56.8 MW in Commercial, and 3.5 MW in residential).

107 *Id*.

108 Exh. PG&E-6 at 7-6:13-15.

109 *Id*. at 2-4 n.9; *id*. at 2-11:4-13.

110 *Id*. at 2-27:6-19.

111 *Id*. at 2-32:1-4.

technologies," directed that PG&E's Expanded Pilot 2 "should prioritize" customers "that previously adopted technologies that enable responses to a dynamic price signal," and directed PG&E to "prioritize working with customers with existing enabling technologies."[112] It also approved $3.6 million for "ASP technology integration and automation with pilot price signal."[113]

Q: Does PG&E carry that technology focus into HFP 2.0?

A: Not consistently. PG&E proposes to add residential customers on E-TOU-D to HFP, a rate "which does not have technology requirements," while observing that customers with automated thermostats may be able to respond to hourly prices.[114] That departs from the emphasis the Commission placed on customers with load shifting technologies when it authorized the pilots.[115] Table 2-1 reports enrollment by pilot and sector, not by whether the customer uses automation, and I have not found in PG&E's testimony a comparison of load response between customers with and without automation.[116] PG&E nonetheless asks the Commission to fund the pilots at a scale sized for up to 16,000 service agreements.[117]

2. CalCCA Proposes an Automation Requirement for Non-Residential HFP Participation

Q: What do you propose?

A: I propose that, as a condition of enrolling and remaining enrolled in HFP, each participating non-residential service agreement be served by a qualifying automation device or service: equipment or software that automatically adjusts the customer's load in response to HFP price signals, without requiring the customer to take manual action on each price change. The requirement is one of deployment, not performance. Customers would not be required

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112 D.24-01-032 at 2; *id*. at 35; *id*., Conclusion of Law 14.

113 *Id*., Attachment A, Table A-2.

114 PG&E-06 at 2-32:5-8, 11-13.

115 Compare Exh. PG&E-6 at 2-32:11-13 (proposing to add E-TOU-D, a rate that "does not have technology requirements"), with D.24-01-032 at 2 (expanding the pilot to residential, commercial, and industrial customers "with load shifting technologies"); D.24-01-032 at 35 (directing PG&E to "prioritize working with customers with existing enabling technologies"); D.24-01-032, Conclusion of Law 14 (Expanded Pilot 2 "should prioritize" customers "that previously adopted technologies that enable responses to a dynamic price signal").

116 Exh. PG&E-6 at 2-4 (Table 2-1).

117 *Id*. at 2-37:34 to 2-38:2.

to achieve a specified load reduction, and would remain free to override the automation at any time.

Q: What would count as qualifying automation?

A: The requirement should be technology neutral. Qualifying automation could be customer-owned or provided by an ASP, and could include, for example, a smart thermostat configured to respond to HFP prices, managed EV charging, a battery storage controller, a building or process energy management system, an agricultural pumping controller, or an ASP platform that automatically schedules or dispatches controllable load. PG&E already publishes HFP prices programmatically for this purpose,[118] and already pays ASPs in HFP Pilot 2 based on enrolled controlled load, which means a mechanism for identifying controlled load exists.[119]

Q: Is the requirement consistent with PG&E's ASP proposal?

A: Yes. PG&E's proposed ASP model is built around automating customer load response across residential, agricultural, commercial, industrial, and BEV customers, with payments tied to enrollment and demonstrated load response.[120] PG&E requests $3.6 million to support that model.[121] Because customer-owned equipment would also qualify, the requirement does not create dependence on any single provider.

Q: Will the requirement reduce enrollment?

A: It may reduce enrollment compared with an unconditioned opt-in pilot. But PG&E describes HFP as designed to incent load response, not to maximize the number of enrolled accounts. Enrollment that earns credit without load shift does not advance that purpose, and for CCAs it creates generation credit exposure without a corresponding system benefit. Participation in HFP is also voluntary, so the requirement conditions access to a pilot rate rather than imposing an obligation on any customer. If enrollment is lower than PG&E has forecast, PG&E's program administration costs should be lower as well,[122] which is a further reason for the reasonableness review I recommend in Section V.C.

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118 *Id*. at 2-11:4-13.
119 *Id*. at 2-26:28-31.
120 *Id*. at 2-27:3-22.
121 *Id*. at 2-27:23-29.
122 Attachment KJC-2 (PG&E Response to CalCCA DR 9.04).

Q: Does an automation requirement fully resolve the cost-shift concerns you identified?

A: No. A customer with automation can still have an incidentally favorable load shape, and the RNA concerns I described in Section III remain. The requirement addresses the narrower problem that credits can be earned with no change in load at all, by tying participation to the means of changing load rather than relying on PG&E's assertion that customers with favorable load shapes are creating value. This proposed requirement complements, and does not replace, the analyses I recommend PG&E perform before the RNA is adopted.

C. Recommendations If the Commission Adopts the RNA

Q: What do you recommend in this Section?

A: If the Commission approves PG&E's RNA proposal, it should also:

- Require PG&E to first serve, before HFP 2.0 is implemented: (1) a quantitative analysis of the RNA's customer-level, class-level, and participant/non-participant cost incidence, including the distribution of resulting credits and charges among customers within each rate schedule; (2) the results of its research on a fixed monthly charge alternative, together with a schedule for completing it; and (3) a commitment to report RNA outcomes by load-serving entity;
- Confirm that CCAs retain the ability to modify RNA values for their own customers, and require PG&E to provide itemized estimates of the costs CCAs would bear under each customization option, which PG&E has said are the CCAs' responsibility;[123]
- Require PG&E to document the CCA customization options PG&E has confirmed in discovery in its implementing advice letter or in supplemental testimony;
- Require PG&E to clarify, in supplemental testimony, how the exit ramp would apply to CCA customers;
- Direct PG&E to preserve subscriptions as an optional feature, as PG&E itself says it may consider after HFP 2.0;
- Require, as a condition of enrolling and remaining enrolled in HFP, that each participating non-residential service agreement use a qualifying, technology neutral automation device or service that can automatically adjust load in response to HFP prices, while allowing customers to override the automation; and

[123] *See id*. (PG&E Responses to CalCCA DRs 8.16 and 8.27(a)).

- Adopt CalCCA's recommendations regarding customer education described in Section III above.

V. THE COMMISSION SHOULD REQUIRE PG&E TO SUPPLEMENT ITS TESTIMONY ON COST RECOVERY AND ALLOCATION AND SHOULD ADOPT GUARDRAILS ON COST RECOVERY

A. The Commission Should Require PG&E To Supplement Its Cost Recovery Proposal on Cost Allocation Issues

Q: What is PG&E's cost recovery proposal?

A: PG&E proposes to continue the cost recovery mechanisms authorized for the existing pilots. PG&E would true-up shadow bill credits annually through its Annual Electric True-up process; recover the distribution component of any shortfall from bundled and unbundled customers through DRAM; and recover the generation component from bundled customers only through ERRA.[124] PG&E would track and record "all costs for the Stop Gap Proposal" in the Expanded Pilots Subaccount of the DRTPMA and seek recovery through a general rate case, subject to reasonableness review.[125]

Q: What is missing from that proposal?

A: PG&E has not proposed how the costs recorded in the DRTPMA will ultimately be allocated. PG&E confirms that neither its opening testimony nor D.24-01-032 specifies the allocation, and that PG&E will make a recovery proposal only when it later seeks cost recovery.

The ordering language from D.24-01-032 only directs that implementation costs be recorded in a DRTPMA subaccount and recovered in a general rate case.[126] But the Commission's reasoning is more specific. It stated that "[e]xpanded pilot implementation costs should be recovered from all bundled and unbundled customers," because the pilots benefit all ratepayers and a large portion of the costs are upfront and administrative costs that are difficult to attribute to bundled or CCA customers.[127] PG&E's response does not address that reasoning, and PG&E has not said which of the roughly $26.5 million in costs it considers attributable to bundled customers, to unbundled customers, or to both.

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124 Exh. PG&E-6 at 8-1:4-19; *id*. at 8-1:27 to 8-2:21.
125 *Id*. at 8-3:10-15.
126 D.24-01-032, Conclusion of Law 31(a).
127 *Id*. at 55-56.

Q: Why is that a problem for CCAs and unbundled customers?

A: There are three concerns.

First, under D.24-01-032, CCA customers pay their share of PG&E's implementation costs, which the Commission directed be recovered from all bundled and unbundled customers because the pilots benefit all ratepayers.[128] CalCCA itself argued in that proceeding that the pilots benefit the grid for all customers.[129] CalCCA does not dispute the principle. But it means that CCA customers will help fund a $26.5 million program for which PG&E proposes to eliminate the CCA-side enrollment incentive, an inconsistency I address in Section II.

Second, the Commission's all-customer rationale does not necessarily apply to all costs. The Commission did not apply this rationale to the generation component of shadow bill credits; it assigned these costs to bundled customers only because that component can be directly attributed. Further, the Commission generally indicated that cost recovery should follow cost causation principles.[130] PG&E should be required to identify which of its proposed costs, if any, relate solely to generation service for its bundled customers. It should further be required to identify the implementation and maintenance costs CCAs will have to bear if they choose to customize their generation-side RTP rate.[131]

Third, by the time PG&E proposes an allocation in a future general rate case, the costs will already have been incurred, and the practical ability of CCAs to influence how they are allocated will be limited.

Q: What do you recommend regarding cost allocation?

A: I recommend that the Commission: (1) require PG&E to submit supplemental testimony in this proceeding that itemizes the Stop-Gap implementation costs and identifies any that are attributable solely to generation service for bundled customers, supported by cost-causation analysis; (2) allow intervenors an opportunity to respond; and (3) order that any costs demonstrated to be attributable solely to bundled generation service be recovered

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128 *Id*. at 55-56.
129 *Id*. at 54-55.
130 *Id*. at 55-56.
131 Attachment KJC-2 (PG&E Response to CalCCA DR 8.27(a)).

from bundled customers only, consistent with the cost-causation principles the Commission applied to generation costs in D.24-01-032.

B. PG&E's Request For Post-Decision Cost-Update Authority Is Improperly Open-Ended

Q: What is PG&E requesting regarding updates to its cost estimates?

A: PG&E requests "the opportunity to file a Tier 2 Advice Letter within 45 days of the Final Decision to update cost estimates based on the CPUC's Final Decision," stating that the final design "may require substantively higher or lower costs to implement than the rate and program design that is presented here in this testimony."[132] PG&E also requests authority to file a Tier 2 Advice Letter for additional funding if enrollment exceeds 16,000 service agreements, at an estimated annual cost of about $260,000 per 2,000 service agreements above that level.[133]

Q: Has PG&E provided any estimate of how much those updates could change its request?

A: No. PG&E has not estimated the range by which its requested costs could change through the proposed Tier 2 Advice Letter process. PG&E states that it cannot develop a cost range for the unknown potential outcomes of the Commission's final decision. PG&E identifies multiple design choices that could affect its budget, including the treatment of subscriptions, the RNA, credit-and-charge billing, dual participation, marketing, education and outreach, measurement and evaluation, and the proposed ASP and CCA engagement and funding approaches.[134] PG&E does not quantify the cost impact of any of those variables.

Q: Why is that a concern?

A: Approving the Stop-Gap Proposal as proposed would effectively grant PG&E a blank check for post-decision cost adjustment. The Commission would authorize $26.5 million without any information about how far that figure could move. In my March testimony, I explained that the Tier 2 Advice Letter process does not provide the formalities of a Commission proceeding, does not confer discovery rights on intervenors, and does not

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132 Exh. PG&E-6 at 2-37:10-15; *see also id*. at 2-42 (Table 2-9, line 11).

133 *Id*. at 2-37:34 to 2-38:5.

134 Attachment KJC-2 (PG&E Response to CalCCA DR 8.07(a)-(b)).

provide a holistic view of the utility's costs.[135] Those concerns apply with equal force here. Given the scale of the unresolved design variables PG&E itself identifies, the ratepayer impact of this proposed approach could be significant.

Q: What guardrails do you recommend?

A: If the Commission authorizes any post-decision cost-update process, it should adopt the following guardrails:

- Before the Commission issues a proposed decision, PG&E should be required to serve high and low cost estimates tied to specific decision scenarios (for example, RNA adopted as proposed versus modified or rejected, and CCA incentive retained versus discontinued);
- Any authorized Tier 2 Advice Letter process should be limited to conforming PG&E's estimates to the specific design elements the Commission adopts, and should not alter the allocation of costs among customer groups;
- Any updated estimate exceeding the authorized incremental budget by more than 10 percent should be filed through a process that provides notice, an opportunity to protest, and discovery rights, such as PG&E's next general rate case; and
- Any request for additional funding associated with enrollment above 16,000 service agreements should identify enrollment by LSE to track enrollment by provider and be subject to the same allocation determination the Commission makes in response to my recommendation in Section V.A.

C. PG&E's Program Administration Forecast Should Be Supported with Staffing and Cost Detail

Q: Has PG&E supported its program administration forecast?

A: PG&E supports its program administration forecast only in general terms. It requests approximately $14.8 million for program administration and customer support—about 1.8 times its $8.2 million request for pricing, billing, and customer relationship-management systems.[136]

PG&E explains that the categories are not directly comparable because program administration relies on labor-intensive internal staff and contracted resources, while

[135] Prepared Direct Testimony of Kyra J. Coyle on Behalf of the California Community Choice Association (Mar. 9, 2026), pp. 14-15.

[136] Exh. PG&E-6 at 2-39 (Table 2-8, lines 1-2, column (d)).

systems costs largely reflect vendor implementation and software-as-a-service expenses.[137] PG&E further explains that the majority of the costs for program administration will be provided through contractors to fill the roles of program management, business product architect, and customer operations and analytics.[138] PG&E describes the budget as supporting "upwards of 16,000 customer services," compared to the 2,352 service agreements enrolled today.[139] However, the only program administration function that increases overtime is that of the customer operations and analytics as additional resources will be added as projected enrollment levels increase.[140]

Q: What do you recommend?

A: PG&E proposes to record these costs in the DRTPMA and seek recovery in a general rate case subject to reasonableness review.[141] I recommend that the Commission specify that, in that review, PG&E must provide the staffing counts, labor-rate assumptions, and vendor contract costs underlying its program administration costs, and must demonstrate that the costs recovered are consistent with actual, rather than forecast, enrollment.

VI. THE COMMISSION SHOULD DIRECT A COLLABORATIVE PROCESS FOR THE DATA EXCHANGE USED TO PREVENT DOUBLE COMPENSATION AND CONFIRM THAT THE DUAL ENROLLMENT CHECKS ARE ADEQUATELY PREVENTING DOUBLE COMPENSATION

Q: How does PG&E currently prevent double compensation involving CCA programs?

A: PG&E claims that it verifies dual participation at enrollment, using the California Independent System Operator (CAISO) Demand Response Registration System for supply-side programs. For CCAs participating in HFP, and for non-PG&E event-based load-modifying programs, PG&E "exchanges Excel files with CCAs every two weeks," and asks CCAs to respond within two to five business days.[142] PG&E also acknowledges that it lacks visibility into whether customers participate in CCA event-based programs, which it describes as a major obstacle.[143]

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137 Attachment KJC-2 (PG&E Response to CalCCA DR 8.19).
138 *Id*. (PG&E Response to CalCCA DR 9.04).
139 *Id*. (PG&E Response to CalCCA DR 8.19); Exh. PG&E-6 at 2-4 (Table 2-1).
140 Attachment KJC-2 (PG&E Response to CalCCA DR 9.04).
141 Exh. PG&E-6 at 8-3:10-15.
142 Attachment KJC-2 (PG&E Response to CalCCA DR 8.25).
143 Exh. PG&E-6 at 4-2:9-19.

Q: What additional data does PG&E say it may need from CCAs?

A: PG&E identifies both program-level and customer-level information that it considers necessary to prevent double compensation. The requested program-level information includes the program name and administrator, incentive structure, event triggers and dispatches, baseline methodology, and impact-allocation rules. The customer-level information requested includes service agreement identifiers, participation dates, per-event performance, and event-specific payments or credits. PG&E does not specify how frequently CCAs would need to provide that information.[144]

Q: What concerns does CalCCA have about that approach?

A: There are two. First, much of this information is competitively sensitive. PG&E itself acknowledges that protecting confidential information of entities that operate competing programs is important.[145] Yet PG&E has "not evaluated any other data-sharing protocols, confidentiality protections, or system changes specific to HFP CCA program participation" beyond the Excel exchange and the non-disclosure agreements it typically uses.[146] Second, a manual, biweekly file exchange may not scale as enrollment grows from 2,352 service agreements toward the 16,000 for which PG&E has sized HFP 2.0.[147]

Q: What do you recommend?

A: I recommend that the Commission review the dual enrollment check process to ensure that PG&E is adhering to its own stated process to prevent dual compensation. I also recommend the Commission direct PG&E to convene a stakeholder process with CCAs to define the appropriate dataset, frequency of exchange, and confidentiality protections necessary to prevent double compensation involving CCA programs, and to evaluate a more automated data exchange. PG&E should not impose any expanded data requirement on CCAs as a condition of participation until that process is complete.

Q: Does this conclude your testimony?

A: Yes.

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144 Attachment KJC-2 (PG&E Response to CalCCA DR 8.25).
145 Exh. PG&E-6 at 4-2:20-23.
146 Attachment KJC-2 (PG&E Response to CalCCA DR 8.26).
147 Exh. PG&E-6 at 2-37:34 to 2-38:2.

Attachment KJC-1

CV of Kyra J. Coyle



KYRA J. COYLE

Principal

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EDUCATION

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

Minor, Computer Applications, Dakota Wesleyan University

KEY EXPERTISE

Economic and Financial Analysis

Expert Witness and Litigation Support

Financial Forecast, Cost of Service, and Rate Design

Power Supply Contract Negotiations

Large Load Tariff Design

Transmission Revenue Requirement Filings

FERC Accounting

Regulatory Policy and Affairs

Strategic Planning

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

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

RELEVANT EXPERIENCE

Financial Forecasting, Revenue Requirement, and Regulatory Strategy

Ms. Coyle provides strategic financial leadership for regulated utilities, specializing in revenue requirement development, long-term forecasting, and regulatory strategy. Her work supports rate case filings, capital investment planning, and sustainable financial performance across electric and natural gas utilities.

- Developed and supported retail electric, natural gas, transmission, ancillary service, standby, and special contract rate studies.
- Led development and filing of rate case applications aligned with corporate strategic plans.
- Directed revenue requirement analyses and regulatory filings.
- Managed financial strategy supporting approximately $1.9 billion in rate base.
- Secured approval for a major transmission project (~260 miles).
- Conducted long-term financial planning and forecasting for regulated and non-regulated utility entities.
- Participated in executive-level strategic initiatives including capital deployment and long-term operational planning.
- Developed equity management plans to support financial stability, capital structure objectives, and long-term regulatory strategy.
- Performed economic and financial analysis to support executive decision-making, capital planning, and regulatory initiatives.
- Supported regulatory filings and strategic planning efforts with detailed financial modeling and documentation.

KYRA J. COYLE
Principal

Clients/Project Experience

- Office of Public Utility Counsel (OPUC)
- Homer Electric Association, Inc.
- Cities Served by Texas Gas Service Company
- Joint Community Choice Aggregators
- Stadion, LLC
- Vitesse, LLC
- City of Chicago
- SABIC Innovative Plastics Mount Vernon, LLC

Cost of Service, Rate Design, and Tariff Development

Ms. Coyle has extensive experience developing retail electric and natural gas rates, performing cost of service analyses, and designing specialized tariffs. Her work includes complex large-load negotiations and development of innovative rate structures to support economic development initiatives.

- Designed and evaluated retail electric and natural gas rates.
- Developed large load tariffs and negotiated power supply contracts.
- Allocated generation and transmission costs for high-density power customers.
- Supported development of innovative tariff offerings to promote economic development.
- Conducted cost allocation and financial modeling to support rate strategy decisions.
- Developed and supported large load tariff design for high-density and industrial customers to ensure appropriate cost allocation and revenue recovery.
- Negotiated and financially modeled power supply contracts, evaluating contract terms, pricing structures, and long-term financial impacts.
- Performed fuel reconciliation analyses to support accurate recovery of fuel costs and regulatory compliance.
- Evaluated and supported recovery of system restoration costs through cost allocation methodologies and regulatory documentation.
- Supported applications for Certificates of Public Convenience and Necessity (CPCN) by preparing financial analysis and documentation demonstrating project need and economic feasibility.

Clients/Project Experience

- California Community Choice Association (CalCCA)
- Joint Community Choice Aggregators
- Joint Community Choice Aggregators
- Office of Public Utility Counsel (OPUC)
- Vitesse, LLC
- SABIC Innovative Plastics Mount Vernon, LLC

Expert Witness and Litigation Support

Ms. Coyle has provided expert witness testimony and litigation support on revenue requirement and cost of service matters before state commissions and FERC. She supports regulatory proceedings with defensible financial analysis and strategic testimony preparation.

- Provided expert witness testimony on revenue requirement and cost of service issues before:
  - State public utility commissions
  - Federal Energy Regulatory Commission (FERC)

- Delivered litigation support related to:
  - Revenue requirement

Cost of service

Rate-related regulatory matters

- Served as expert witness on financial and regulatory policy matters before legislative and regulatory bodies.
- Provided expert witness and litigation support related to revenue requirement, cost of service, rate design, and regulatory cost recovery issues.

Clients/Project Experience

- Office of Public Utility Counsel
- Homer Electric Association, Inc.
- Cities Served by Texas Gas Service Company
- Joint Community Choice Aggregators
- Stadion, LLC
- Vitesse, LLC
- Eastern New England Consumer-Owned Systems
- City of Chicago
- SABIC Innovative Plastics Mount Vernon, LLC

Transmission and Regulatory Accounting

Ms. Coyle applies FERC accounting principles and regulatory compliance expertise to transmission revenue requirement filings and related proceedings. Her experience bridges financial reporting and regulatory strategy.

- Prepared and supported transmission revenue requirement filings.
- Applied FERC accounting principles in rate and regulatory matters.
- Supported compliance filings and regulatory documentation.
- Supported transmission revenue requirement compliance activities by preparing financial analyses and applying regulatory accounting principles.
- Assisted with transmission-related regulatory documentation and cost recovery support consistent with FERC accounting practices.

Clients/Project Experience

- Eastern New England Consumer-Owned Systems
- Alaska Railbelt Transmission Organization (RTO)
- Homer Electric Association, Inc.

Financial Leadership and Strategic Management

In prior leadership roles, Ms. Coyle directed regulatory and financial strategy for multi-state electric and natural gas utilities. She partnered with executive leadership and operations teams to align financial planning with long-term capital and regulatory objectives.

Black Hills Corporation

Director of Regulatory/Finance – Electric and Natural Gas Utilities (WY, MT, SD)

- Led all financial and regulatory matters for electric and gas utilities.

- Directed rate case filings and regulatory strategy.
- Negotiated contracts with large industrial customers.
- Built relationships with regulators, legislators, and stakeholders.
- Executed long-term financial strategy initiatives.

Senior Manager of Finance and Regulatory

- Responsible for forecasting and strategic planning across regulated and non-regulated operations.
- Financial modeling for purchase power agreements and capital projects.
- Participated in divestiture of 49.9% interest in non-regulated entity.
- Partnered with operations to optimize financial performance.

Professional Finance Senior/Principal

- Budgeting and forecasting for power generation assets.
- Managed capital and O&M budgets exceeding $50M annually.
- Financial modeling of PPAs.
- Maximized asset value through operational coordination.

Accounting and Corporate Finance Experience

Ms. Coyle provided accounting and financial leadership for a multi-entity organization, overseeing financial reporting, budgeting, consolidation, and audit coordination. She supervised accounting, purchasing, and logistics functions while serving as the primary audit liaison. Her experience includes implementation and restructuring of ERP systems, including redesign of the chart of accounts and enterprise-wide NetSuite training to improve financial reporting accuracy and operational efficiency.

U.S. Bentonite Processing, Inc.

Accounting Manager

- Led accounting support staff and supervised purchasing/logistics.
- Prepared monthly financial statements for board of directors.
- Managed close, consolidation, and budgeting for three U.S.-based companies.
- Primary audit contact.
- Implemented NetSuite restructuring including chart of accounts redesign and company-wide training.

Record of Testimony: **KYRA J. COYLE**

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
1. Rocky Mountain Power	Docket No. 2000-710-ER-26	In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Service Rates Overall by Approximately $70.5 Million per Year or 8.8 Percent, to Modify Schedule 92 Insurance Cost Adjustment Tariff, to Establish a New Schedule 96 Asset Sale Adjustment Tariff, and to Revise the Schedule 95 Energy Cost Adjustment Mechanism	Wyoming Public Service Commission	Office of Consumer Advocate	2026
2. PacifiCorp	Docket No. UE-463	Advice No. 25-015, Schedule 401 Service to New Large Energy Facilities	Public Utility Commission of Oregon	Vitesse, LLC	2026
3. Chugach Electric Association, Inc.	Docket No. U-25-036	In the Matter of the Revenue Requirement Study and Rate Design Revisions Designated as TA577-8 Filed by CHUGACH ELECTRIC ASSOCIATION, INC.	The Regulatory Commission of Alaska	Golden Valley Electric Association, Inc.	2026
4. Pacific Gas and Electric Company	Docket No. A.24-09-014	Application of Pacific Gas and Electric Company to Revise its Electric Marginal Costs, Revenue Allocation, and Rate Design	California Public Utilities Commission	California Community Choice Association	2026
5. El Paso Electric Company	SOAH Docket No. 473-26-08223 PUC Docket No. 59137	Application of El Paso Electric Company for Approval of a System Resiliency Plan	Public Utility Commission of Texas	Office of Public Utility Counsel	2026
6. Texas-New Mexico Power Company	SOAH Docket No. 473-26-05799 PUC Docket No. 58964	Application of Texas-New Mexico Power Company for Authority to Change Rates	Public Utility Commission of Texas	Office of Public Utility Counsel	2026
7. Railbelt Transmission Organization	Docket No. U-25-028	In the Matter of the Initial Nondiscriminatory Open Access Transmission Tariff Designated as TA1-8001 Filed by the Railbelt Transmission Organization	The Regulatory Commission of Alaska	Homer Electric Association, Inc.	2025

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
8. Texas Gas Service Company, a Division of ONE Gas, Inc.	OS-25-00028202	Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc. to Change Gas Utility Rates Within the Unincorporated Areas of the Central-Gulf, West North, and Rio Grande Valley Service Areas	Railroad Commission of Texas	Cities Served by Texas Gas Service Company	2025
9. Pacific Gas and Electric Company	Docket No. A.24-10-014	Application of Pacific Gas and Electric Company for Approval of Its Billing Modernization Initiative	California Public Utilities Commission	Joint Community Choice Aggregators	2025
10. CenterPoint Energy Houston Electric, LLC	SOAH Docket No. 473-25-18704 PUC Docket No. 58028	Application of CenterPoint Energy Houston Electric, LLC for Determination of System Restoration Costs	Public Utility Commission of Texas	Office of Public Utility Counsel	2025
11. El Paso Electric Company	SOAH Docket No. 473-25-11219 PUC Docket No. 57568	Application of El Paso Electric Company for Authority to Change Rates	Public Utility Commission of Texas	Office of Public Utility Counsel	2025
12. Southwestern Electric Power Company	SOAH Docket No. 473-24-22136 PUC Docket No. 56643	Application of Southwestern Electric Power Company for Authority to Reconcile Fuel Costs	Public Utility Commission of Texas	Office of Public Utility Counsel	2025
13. CenterPoint Energy Houston Electric, LLC	SOAH Docket No. 473-25-05323 PUC Docket No. 57271	Application of CenterPoint Energy Houston Electric, LLC for Determination of System Restoration Costs	Public Utility Commission of Texas	Office of Public Utility Counsel	2025
14. PacifiCorp	Docket No. 24-035-04	Application of Rocky Mountain Power for Authority to Increase Its Retail Electric Utility Service Rates in Utah and for Approval of Its Proposed Electric Service Schedules and Electric Service Regulations	Public Service Commission of Utah	Stadion, LLC	2024
15. PacifiCorp	Docket No. UE 433	PacifiCorp d/b/a Pacific Power Request for General Rate Revision	Public Utility Commission of Oregon	Vitesse, LLC	2024

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
16. CenterPoint Energy Houston Electric, LLC	SOAH Docket No. 473-24-13232 PUC Docket No. 56211	Application of CenterPoint Energy Houston Electric, LLC for Authority to Change Rates	Public Utility Commission of Texas	Office of Public Utility Counsel	2024
17. Constellation Mystic Power, LLC.	Docket No. ER18-1639-027	Annual Fixed Revenue Requirement, Capital Expense Recovery, and Stipulated Variable Cost Recovery for Mystic 8 & 9 Fuel Security System	Federal Energy Regulatory Commission	Eastern New England Consumer-Owned Systems (ENECOS)	2024
18. Peoples Gas Light and Coke Company	Docket No. 23-0069	Proposed General Increase in Gas Rates and Revisions to Other Terms and Conditions of Service	Illinois Commerce Commission	City of Chicago	2024
19. Southern Indiana Gas and Electric Company DBA CenterPoint Energy Indiana South	Cause No. 45990	Authority to Modify its Rates and Charges for Electric Utility Service Through a Phase-In of Rates…	Indiana Utility Regulatory Commission	SABIC Innovative Plastics Mount Vernon, LLC	2024
20. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-228-EN-23	Certificate of Public Convenience and Necessity to Construct and Operate a New 115 kV Substation, Two New 115 kV Transmission Lines, Modification and Extension of Four 115 kV Transmission Lines, Four New 115 kV Load-Serving Transmission Lines and Related Facilities	Wyoming Public Service Commission	--	2023
21. Black Hills Power, Inc. DBA Black Hills Energy	Docket No. 20002-131-EA-23	Proposed Modification of the Neil Simpson II Generation Facility to a Dual Fuel Source and Request for a Determination Regarding the Need to File for a Certificate of Public Convenience and Necessity	Wyoming Public Service Commission	--	2023
22. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-225-EM-23	Authority to Increase Its Power Cost Adjustment by $0.00872 per Kilowatt Hour	Wyoming Public Service Commission	--	2023

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
23. Cheyenne Light, Fuel, and Power Company and Black Hills Power, Inc. DBA Black Hills Energy	Docket No. 20003-223-ET-23	Authority to Establish a Low-Carbon Surcharge Tariff and Rate	Wyoming Public Service Commission	--	2023
24. Cheyenne Light, Fuel, and Power Company and Black Hills Power, Inc. DBA Black Hills Energy	Docket No. 20002-127-ET-23	Authority to Establish a Low-Carbon Surcharge Tariff and Rate	Wyoming Public Service Commission	--	2023
25. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-221-EA-23	Establish Intermediate Low-Carbon Portfolio Standards and Requirements	Wyoming Public Service Commission	--	2023
26. Black Hills Power, Inc. DBA Black Hills Energy	Docket No. 20002-126-EA-23	Establish Intermediate Low-Carbon Portfolio Standards and Requirements	Wyoming Public Service Commission	--	2023
27. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-217-EM-23	Authority to Decrease Its Power Cost Adjustment by $0.03149 per Kilowatt-Hour	Wyoming Public Service Commission	--	2023
28. Black Hills Wyoming Gas, LLC DBA Black Hills Energy	Docket No. 30026-78-GR-23	Authority to Implement a General Rate Increase of $19,262,412 per Annum and Extend Its Wyoming Integrity Rider	Wyoming Public Service Commission	--	2023
29. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-214-ER-22	A General Rate Increase of $15,366,026 per Annum and Authority to Revise Its Power Cost Adjustment Mechanism	Wyoming Public Service Commission	--	2022
30. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-213-EM-22	Authority to Increase Its Power Cost Adjustment by $0.00129 per Kilowatt-Hour	Wyoming Public Service Commission	--	2022

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
31. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-211-EM-22	Authority to Pass on a Blockchain Interruptible Service Customer Credit Adjustment Rate of $0.00 per Kilowatt-Hour Effective June 1, 2022	Wyoming Public Service Commission	--	2022
32. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-210-ET-22	Revise the Demand Side Management Surcharge Rate, Effective June 1, 2022	Wyoming Public Service Commission	--	2022
33. Cheyenne Light, Fuel, and Power Company and Black Hills Power, Inc. DBA Black Hills Energy	Docket No. 20003-209-EA-22	Establish Intermediate Low-Carbon Energy Portfolio Standards and Requirements	Wyoming Public Service Commission	--	2022
34. Cheyenne Light, Fuel, and Power Company and Black Hills Power, Inc. DBA Black Hills Energy	Docket No. 20002-123-EA-22	Establish Intermediate Low-Carbon Energy Portfolio Standards and Requirements	Wyoming Public Service Commission	--	2022
35. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-208-EA-22	Authority to Increase Its Voluntary Renewable Energy Rider Rate to $0.47 per Month per 100-KWh Block, Effective April 1, 2022	Wyoming Public Service Commission	--	2022
36. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-206-EN-22	A Certificate of Public Convenience and Necessity to Construct and Operate One New 230 kV Substation, Two Replacement 115 kV Substations, Three 230 kV Transmission Lines, Two 115 kV Transmission Lines and Related Facilities in Converse, Laramie, Goshen and Platte Counties on Wyoming and Scotts Bluff County in Nebraska	Wyoming Public Service Commission	--	2022

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
37. Black Hills Wyoming Gas, LLC DBA Black Hills Energy	Docket No. 30026-68-GM-22	Authority to Implement Wyoming Integrity Rider Rates of $0.0231 per Therm for Residential General Service, $0.0139 per Therm for Small General Service, $0.0148 per Therm for Medium General Service, $0.0092 per Therm for Large General Service, and $0.0285 per Therm for On-System Transportation Service	Wyoming Public Service Commission	--	2022
38. Black Hills Wyoming Gas, LLC DBA Black Hills Energy	Docket No. 30026-67-GM-22	Authority to Decrease the Revenue Adjustment Mechanism Rate By $0.0058 per Therm	Wyoming Public Service Commission	--	2022
39. Black Hills Wyoming Gas, LLC DBA Black Hills Energy	Docket No. 30026-66-GP-22	Authority to Pass on a Gas Cost Rate Decrease of $0.1155 per Therm	Wyoming Public Service Commission	--	2022
40. Black Hills Wyoming Gas, LLC DBA Black Hills Energy	Docket No. 30026-65-GN-22	Determination of CPCN Requirements Regarding the Relocation of an Existing Transmission Pipeline and Related Facilities	Wyoming Public Service Commission	--	2022
41. Black Hills Wyoming Gas, LLC DBA Black Hills Energy	Docket No. 30026-63-GP-22	Authority to Pass on a Gas Cost Rate Decrease of $0.0026 per Therm	Wyoming Public Service Commission	--	2022
42. Black Hills Wyoming Gas, LLC DBA Black Hills Energy	Docket No. 30026-60-GM-22	Authority to Increase the Revenue Adjustment Mechanism Rate by $0.0022 Per Therm	Wyoming Public Service Commission	--	2022
43. Black Hills Wyoming Gas, LLC DBA Black Hills Energy	Docket No. 30026-57-GT-22	Authority to Decrease the Energy Efficiency Surcharge for Residential Customers by $0.0034 per Therm and Increase It by $0.0006 per Therm for Non-Residential Customers	Wyoming Public Service Commission	--	2022

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
44. Black Hills Wyoming Gas, LLC DBA Black Hills Energy	Docket No. 30026-55-GP-22	Authority to Pass on a Wholesale Gas Cost Increase of $0.0669 per Therm	Wyoming Public Service Commission	--	2022
45. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-205-ET-21	Approval of the 2022-2024 Demand Side Management Program Plan by November 1, 2021, for Implementation on January 1, 2022	Wyoming Public Service Commission	--	2021
46. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-203-EM-21	Authority to Pass on a Blockchain Interruptible Service Customer Credit Adjustment Rate Of $0.00 Per KWh Effective June 1, 2021	Wyoming Public Service Commission	--	2021
47. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-202-EM-21	Authority to Increase Its Power Cost Adjustment by $0.00246 per Kilowatt-Hour	Wyoming Public Service Commission	--	2021
48. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-201-EN-21	Certificate of Public Convenience and Necessity to Construct and Operate Two 115 kV Substations, Associated Transmission Lines, and Related Facilities in Laramie County, Wyoming	Wyoming Public Service Commission	--	2021
49. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-200-ET-21	Authority to Update Its Demand Side Management Surcharge Rate, Effective June 1, 2021	Wyoming Public Service Commission	--	2021
50. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-199-EA-21	Authority to Increase Its Voluntary Renewable Energy Rider Rate to $0.43 per Month per 100-KWh Block, Effective April 1, 2021	Wyoming Public Service Commission	--	2021
51. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-198-EN-21	Certificate of Public Convenience and Necessity to Construct and Operate a 115 kV Substation, Associated Transmission Lines, and Related Facilities in Laramie County, Wyoming	Wyoming Public Service Commission	--	2021

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
52. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-194-EM-20	Authority to Increase Its Power Cost Adjustment by $0.00243 per Kilowatt-Hour Effective July 1, 2020	Wyoming Public Service Commission	--	2020
53. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-193-EN-20	Certificate of Public Convenience and Necessity to Rebuild an Existing 115 kV Transmission Line from Skyline Substation to East Business Park Substation in Laramie County, Wyoming	Wyoming Public Service Commission	--	2020
54. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-190-ET-20	Authority to Update Its Tariff Applicable to the Demand Side Management Margin Revenue Recovery, the Balancing Account and Program Costs	Wyoming Public Service Commission	--	2020
55. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-188-ET-20	Authority to Decrease Its Electric Voluntary Renewable Energy Rider Rate to $0.03 per Month per 100-KWh Block	Wyoming Public Service Commission	--	2020
56. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-182-ET-19	Authority to Update Its Electric and Gas Tariffs Applicable to the Demand Side Management Margin Revenue Recovery, the Balancing Account and Program Costs	Wyoming Public Service Commission	--	2019
57. Cheyenne Light, Fuel, and Power Company DBA Black Hills Energy	Docket No. 20003-173-ET-18	Authority to Implement a Blockchain Interruptible Service Tariff	Wyoming Public Service Commission	--	2018

Attachment KJC-2

PG&E Responses to CalCCA Discovery Requests

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

PG&E Data Request No.:	CalCCA_008-Q001
PG&E File Name:	GRC-2023-PhII_DR_CalCCA_008-Q001
Request Date:	August 18, 2026
Requester DR No.:	008
Requesting Party:	California Community Choice Association
Requester:	Julia Kantor
Date Sent:	September 9, 2026
PG&E Witness(es):	Andrew Au

QUESTION 001

Referring to Exh. PG&E-6 at p. 2-4 (PG&E's statement that CCA engagement "has been important for recruiting customers and enabling load response") and Exh. PG&E-6 at p. 2-35 (PG&E's proposal to discontinue CCA incentive funding):

a. Does PG&E anticipate any reduction in CCA-facilitated recruiting or load response as a result of eliminating the incentive? Please explain why or why not, and the basis for PG&E's conclusion.

b. Please provide any documents in PG&E's possession showing any analyses PG&E has conducted around the impact of CCA incentive funding on customer recruitment and load response.

ANSWER 001

a. PG&E does not propose continuation of CCA incentive funding as part of its Stop Gap Proposal because it appears that CCAs are independently motivated to participate in PG&E's RTP pilots in order to comply with the California Energy Commission's Load Management Standards (LMS) as is explained in exhibit PG&E-6 on lines 19 through 24 of p.2-35 and lines 1-10 on p.2-36. Specifically, PG&E observed that nine of the ten CCAs in PG&E's service area subject to LMS requirements cited participation in PG&E's HFP pilots as a pathway in their approved LMS Compliance Plans. PG&E further notes that CCAs are largely relying on PG&E's RTP pilots to satisfy LMS-related objectives and are able to do so using PG&E's RTP pricing and billing infrastructure, for which CCAs are not charged.

   Accordingly, the basis for PG&E's proposal is that CCA participation is being driven by LMS compliance needs and access to the RTP platform rather than by continuation of the incentive funding. PG&E also noted that under the proposed HFP 2.0 "credit and charge" billing structure, CCAs would be less exposed to funding shortfalls associated with annual true-up reconciliation of unbundled generation charges.

PG&E has not identified, in the cited testimony, a quantitative analysis estimating a specific level of change in CCA recruiting activity or load response that would result from eliminating the incentive. The testimony explains the rationale for discontinuing the incentive but does not present a forecasted reduction (or lack of reduction) in customer recruitment or load response attributable to the funding change.

b. PG&E has not performed a quantitative assessment to estimate the extent to which eliminating the incentive would affect CCA customer recruitment activity or resulting load response. While PG&E has provided its rationale for discontinuing the incentive, it has not developed a forecast of any potential increase or decrease in customer participation or load response attributable to the removal of the funding.

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

PG&E Data Request No.:	CalCCA_008-Q002
PG&E File Name:	GRC-2023-PhII_DR_CalCCA_008-Q002
Request Date:	August 18, 2026
Requester DR No.:	008
Requesting Party:	California Community Choice Association
Requester:	Julia Kantor
Date Sent:	September 9, 2026
PG&E Witness(es):	Andrew Au

QUESTION 002

Referring to Exh. PG&E-6 at p. 2-35: Provide all data, analyses, and/or communications PG&E relied upon in concluding that continuation of CCA incentives is unnecessary because CCAs are "now leveraging participation…to meet LMS guidance."

ANSWER 002

PG&E states that the conclusion described in Exhibit PG&E-6 was based on PG&E's review of publicly filed and approved Community Choice Aggregator ("CCA") Load Management Standards ("LMS") Compliance Plans and the participation status of CCAs in PG&E's Real-Time Pricing ("RTP") pilots.

As described in in exhibit PG&E-6 on lines 19 through 24 of p.2-35 and lines 1-10 on p.2-36, PG&E relied on the observation that:

- CCAs are subject to California Energy Commission ("CEC") LMS requirements to submit hourly dynamic rate proposals and make dynamic rates available to customers, subject to applicable requirements.[1]
- CCAs are largely relying on PG&E's RTP pilots to support those LMS obligations and are able to do so using PG&E's RTP pricing and billing infrastructure, for which CCAs are not charged.
- Of the ten CCAs in PG&E's service area to which the LMS requirements apply, nine cited participation in PG&E's HFP pilots as a pathway in LMS Compliance Plans approved by the CEC in 2025 and 2026.

The testimony specifically identifies the following LMS Compliance Plan filings as support for that conclusion:

[1] California Code of Regulations, Title 20, Division 2, Chapter 4, Article 5, § 1623.1.

- Ava Energy, Clean Version of Ava Community Energy Revised Load Management Standards Compliance Plan (TN #264899, docketed July 18, 2025).
- San José Clean Energy, SJCE Revised LMS Compliance Plan (TN #262497, docketed March 28, 2025).
- Silicon Valley Clean Energy, SVCE LMS Plan (Public Version) (TN #255393, docketed April 2, 2024).
- Central Coast Community Energy, Revised Load Management Standards Plan (TN #266039, docketed September 17, 2025).
- Peninsula Clean Energy, Revised LMS Compliance Plan (TN #262291, docketed March 21, 2025). PG&E cites Peninsula Clean Energy's statement that it is participating in two of PG&E's HFP pilots as a means of pursuing LMS-compliant rate offerings.
- Valley Clean Energy, Revised Load Management Standards Compliance Plan (TN #262691, docketed April 15, 2025).
- Marin Clean Energy, Revised Load Management Standards Plan (TN #268185, docketed January 7, 2026).
- Pioneer Community Energy, Revised Load Management Standards Plan (TN #266073, docketed September 18, 2025).
- CleanPowerSF, Revised Load Management Standards Plan (TN #266041, docketed September 17, 2025).

PG&E's testimony does not identify a separate quantitative study that evaluates whether elimination of CCA incentive funding would affect CCA participation, customer recruitment, or load response. Rather, the testimony explains that PG&E's conclusion was based on the existence of LMS requirements, the approved LMS Compliance Plans cited above, the participation of nine CCAs in PG&E's RTP pilots, and the availability of PG&E's RTP billing and programmatic infrastructure at no charge to participating CCAs.

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase II
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Data Response

PG&E Data Request No.:	CalCCA_008-Q004
PG&E File Name:	GRC-2023-PhII_DR_CalCCA_008-Q004
Request Date:	August 18, 2026
Requester DR No.:	008
Requesting Party:	California Community Choice Association
Requester:	Julia Kantor
Date Sent:	September 9, 2026
PG&E Witness(es):	Andrew Au

QUESTION 004

Referring to Exh. PG&E-6 at p. 2-35 to 2-36: Did PG&E solicit input from participating CCAs before proposing to discontinue the CCA incentive? If so, summarize the input received and how it factored into PG&E's decision to discontinue the incentive. If not, why not?

ANSWER 004

No, PG&E did not solicit input from participating Community Choice Aggregators (CCAs) before proposing to discontinue the CCA incentive. PG&E did not do so because PG&E made a determination that including CCA incentives in our proposal was not appropriate given the California Energy Commission's Load Management Standards (LMS) and CCAs' approved LMS compliance plans. The rationale for this determination is explained in exhibit PG&E-6 on lines 19 through 24 of p.2-35 and lines 1-10 on p.2-36. In its original proposal for the existing HFP pilots, PG&E did not propose funding for CCAs. As noted in the CPUC's *Decision to Expand System Reliability Pilots of Pacific Gas and Electric Company and Southern California Edison Company*, D.24-01-032, CalCCA made the request for funding. The Decision states:

> *CalCCA argued that any CCA should have the option to receive ratepayer funding to administer dynamic rates pilots in their service area." It further argued that CCAs have local knowledge and that administering dynamic rate pilots would help them gain experience ahead of the CEC Load Management Standards deadlines.*[1]

This statement also connects the applicability of funding to the LMS. PG&E anticipates and looks forward to the CCAs input through the regulatory stakeholder process.

[1] D.24-01-032, p.28.

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

PG&E Data Request No.:	CalCCA_008-Q005
PG&E File Name:	GRC-2023-PhII_DR_CalCCA_008-Q005
Request Date:	August 18, 2026
Requester DR No.:	008
Requesting Party:	California Community Choice Association
Requester:	Julia Kantor
Date Sent:	August 25, 2026
PG&E Witness(es):	Rebecca Madsen

QUESTION 005

Referring to Exh. PG&E-6 at p. 8-1 to 8-3:

a. Confirm or deny that CCA (unbundled) customers bear cost responsibility for the distribution-component shortfall through DRAM, while only bundled customers bear cost responsibility for the generation-component shortfall through ERRA. If denied, please explain.

b. Please explain PG&E's proposed cost recovery/cost allocation proposal for the costs to be tracked within the DRTPMA balancing account. Under PG&E's proposal, which customer groups will bear these costs?

ANSWER 005

a. PG&E confirms that CCA (unbundled) customers bear cost responsibility for the distribution-component shortfall through DRAM, and further clarifies that bundled customers also bear cost responsibility for the distribution-component shortfall through DRAM. This is noted in PG&E's opening testimony, Exh. PG&E-6 at page 8-2:

"PG&E proposes to true-up shadow bill credits for the Stop Gap Proposal on an annual basis through its AET process and recover (a) the revenue shortfall from the distribution component of PG&E's bundled and unbundled customers in its existing DRAM balancing account…"

PG&E confirms that only bundled customers bear cost responsibility for the generation-component shortfall through ERRA. This is noted in PG&E's opening testimony, Exh. PG&E-6 at page 8-2:

"PG&E proposes to true-up shadow bill credits for the Stop Gap Proposal on an annual basis through its AET process and recover…(b) the revenue shortfall from the generation component of PG&E's bundled customers in its ERRA."

b. In its opening testimony PG&E did not propose which rate component(s) or from what customer group(s) to recover the Stop Gap Proposal costs proposed to be recorded in the Expanded Pilots Subaccount of the DRTPMA. D.24-01-032, which found it reasonable for PG&E to track and record implementation costs for its HFP Pilots in its existing DRTPMA, also did not specify what rate component(s) or from what customer group(s) the costs should be recovered. When PG&E files to recover the costs recorded in the Expanded Pilots Subaccount of the DRTPMA it will make a proposal for what rate component(s) and from which customer group(s) the costs should be recovered and will abide by the CPUC's decision on this matter.

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

PG&E Data Request No.:	CalCCA_008-Q006
PG&E File Name:	GRC-2023-PhII_DR_CalCCA_008-Q006
Request Date:	August 18, 2026
Requester DR No.:	008
Requesting Party:	California Community Choice Association
Requester:	Julia Kantor
Date Sent:	September 9, 2026
PG&E Witness(es):	Andrew Au

QUESTION 006

Referring to Exh. PG&E-6 at p. 8-1 to 8-2: Provide, for each of the most recent three years for which data is available, the dollar amounts of distribution-component shadow-bill shortfalls recovered through DRAM that are attributable to CCA/unbundled customers, separately from bundled customers.

ANSWER 006

HFP is designed such that it aligns closely with the true cost-to-serve. The dynamic rates in general cannot prevent all cost shifts. However, PG&E notes that the definitions of “shortfalls” and “cost shifts” are very important for this context. Customers that do not participate in dynamic pricing, i.e. TOU customers, are already creating a cost shift themselves because the TOU prices they pay do not match the utility’s cost to serve. While no pricing scheme will be perfectly cost-based, PG&E believes that because the HFP design is more cost-based than TOU rates, customers on HFP are effectively reducing an existing cost shift rather than creating a new one, even without modifying their usage pattern.. In summary, PG&E does not believe there is a shortfall in this context.

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

PG&E Data Request No.:	CalCCA_008-Q007
PG&E File Name:	GRC-2023-PhII_DR_CalCCA_008-Q007
Request Date:	August 18, 2026
Requester DR No.:	008
Requesting Party:	California Community Choice Association
Requester:	Julia Kantor
Date Sent:	September 9, 2026
PG&E Witness(es):	Andrew Au

QUESTION 007

Referring to Exh. PG&E-6 at p. 2-37, and PG&E's statement that

> "PG&E requests the opportunity to file a Tier 2 Advice Letter within 45 days of the Final Decision to update cost estimates based on the CPUC's Final Decision on this proposal. This is important as the final rate and program design that PG&E is required to implement may require substantively higher or lower costs to implement than the rate and program design that is presented here in this testimony":

a. What is the cost range PG&E anticipates could be requested through this Tier 2 Advice Letter process?

b. At this point, what information does PG&E lack that prevents it from finalizing its cost forecast with a higher degree of certainty? What aspects of the Final Decision does PG&E anticipate will impact the final cost forecast?

ANSWER 007

a. PG&E is unable to develop a cost range for unknown potential outcomes in the CPUC's Final Decision in this case.

b. PG&E's cost estimates are based on PG&E's proposed rate and programmatic design for the extended Hourly Flex Pricing (HFP) pilot and revised HFP 2.0 offering. There are a number of unknown rate design and programmatic variables that could affect the budget needed. Changes to these elements could increase or decrease implementation complexity and associated vendor, systems, partner engagement, and administrative costs. These parameters will be determined by the CPUC's Final Decision and include:

    i. Whether the Commission would approve, modify, or reject proposed HFP 2.0 rate and programmatic design elements, including removal of subscriptions, adoption of the revenue neutral adder, the proposed credit-and-charge billing

structure, removal of transactive pricing, customer protection provisions, and other pilot design modifications.

ii. Whether the Commission would modify customer eligibility requirements and/or direct additional rate schedules.

iii. Whether the Commission would adopt a different approach to dual participation, avoiding double compensation, and/or require additional systems, processes, or safeguards to address dual participation issues.

iv. Whether the Commission would require modifications to the proposed ASP engagement or CCA engagement approach and funding.

v. Whether the Commission would require modifications to the proposed Marketing, Education, and Outreach activities.

vi. Whether the Commission would require modifications to the proposed Measurement and Evaluation activities, reporting requirements.

vii. Whether the Commission would require additional functionality, operational processes, or implementation activities beyond those reflected in PG&E's proposed implementation plan.

viii. As yet unknown proposals that may be generated by intervenors to the proceeding and approved by the CPUC.

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

PG&E Data Request No.:	CalCCA_008-Q009
PG&E File Name:	GRC-2023-PhII_DR_CalCCA_008-Q009
Request Date:	August 18, 2026
Requester DR No.:	008
Requesting Party:	California Community Choice Association
Requester:	Julia Kantor
Date Sent:	August 31, 2026
PG&E Witness(es):	Tysen Streib

QUESTION 009

Referring to Exh. PG&E-6 at p. 2-25:

a. Explain if and how the RNA and the "price you see is the price you pay" design will ensure that customers with favorable load shapes do not receive bill benefits without a corresponding change in behavior.

b. Explain if and how the RNA and the "price you see is the price you pay" design will prevent cost shifting onto customers who do not participate in HFP.

ANSWER 009

a. No, the RNA and the "price you see is the price you pay" design will not ensure that customers with favorable load shapes do not receive bill benefits without a corresponding change in behavior. As described in the response to GRC-2023-PhII_DR_CalCCA_008-Q008, the RNA is calculated to be revenue neutral to the schedule as a whole, not revenue neutral for individual customers. Customers with a favorable load shape are using energy when it's cheapest and creating value for the utility, which should be encouraged. See more details in part (b) below.

b. The RNA, the "price you see is the price you pay" design, and dynamic rates in general cannot prevent all cost shifts. However, PG&E notes that the definition of "cost shift" is very important for this context. Customers that do not participate in dynamic pricing, i.e. TOU customers, are already creating a cost shift because the TOU prices they pay do not match the utility's cost to serve. While no pricing scheme will be perfectly cost-based, PG&E believes that because the HFP design is more cost-based than TOU rates, customers on HFP are effectively reducing an existing cost shift rather than creating a new one, even if they are receiving bill benefits without a change in behavior.

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

PG&E Data Request No.:	CalCCA_008-Q010
PG&E File Name:	GRC-2023-PhII_DR_CalCCA_008-Q010
Request Date:	August 18, 2026
Requester DR No.:	008
Requesting Party:	California Community Choice Association
Requester:	Julia Kantor
Date Sent:	August 31, 2026
PG&E Witness(es):	Tysen Streib

QUESTION 010

Referring to Exh. PG&E-6 at p. 2-25:

a. Provide any sensitivity analyses in PG&E's possession showing the range of RNA values across rate schedules.

b. Describe if and how PG&E tested whether the proposed RNA design eliminates (or minimizes) cost shifting among customer classes and between participating and non participating customers.

ANSWER 010

a. PG&E has not performed any RNA calculations beyond those already provided in workpapers.

b. See the response to GRC-2023-PhII_DR_CalCCA_008-Q009. No other testing has been performed.

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PG&E Data Request No.:	CalCCA_008-Q011
PG&E File Name:	GRC-2023-PhII_DR_CalCCA_008-Q011
Request Date:	August 18, 2026
Requester DR No.:	008
Requesting Party:	California Community Choice Association
Requester:	Julia Kantor
Date Sent:	August 31, 2026
PG&E Witness(es):	Tysen Streib

QUESTION 011

Referring to Exh. PG&E-6 at p. 3-4: Explain how the RNA will interact with the proposed removal of peak demand charges. Will this design ensure that customers on schedules with significant demand-driven cost causation are neither over- nor under-collected relative to cost of service? Please explain.

ANSWER 011

The dynamic HFP rate collects the same capacity costs as peak demand charges typically collect. Any difference between the cost-based HFP design and the TOU tariff design are captured within the RNA to ensure that the schedule does not over- or under-collect. See the response to GRC-2023-PhII_DR_CalCCA_008-Q008 for additional information.

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PG&E Data Request No.:	CalCCA_008-Q012
PG&E File Name:	GRC-2023-PhII_DR_CalCCA_008-Q012
Request Date:	August 18, 2026
Requester DR No.:	008
Requesting Party:	California Community Choice Association
Requester:	Julia Kantor
Date Sent:	August 31, 2026
PG&E Witness(es):	Tysen Streib

QUESTION 012

Referring to Exh. PG&E-6 at p. 2-25: Identify any alternatives to the RNA that PG&E considered for collecting non-marginal costs following removal of subscriptions (including, but not limited to, retaining a modified subscription, a fixed monthly charge, or another allocator), and explain why the RNA was selected over such alternatives. If no alternatives were evaluated, please explain why.

ANSWER 012

As mentioned in Exhibit (PG&E-6),[1] PG&E is not considering alternatives to the RNA, but is researching a fixed monthly charge that would reduce or eliminate the RNA. PG&E is just beginning to explore these options and does not have any analysis available.

[1] See Exhibit (PG&E-6), p. 3-7, lines 25-27.

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Data Response

PG&E Data Request No.:	CalCCA_008-Q013
PG&E File Name:	GRC-2023-PhII_DR_CalCCA_008-Q013
Request Date:	August 18, 2026
Requester DR No.:	008
Requesting Party:	California Community Choice Association
Requester:	Julia Kantor
Date Sent:	September 2, 2026
PG&E Witness(es):	Tysen Streib

QUESTION 013

Referring to Exh. PG&E-6 at p. 2-25: Did PG&E solicit input from CCAs regarding the design of the proposed RNA before filing this testimony? If so, please (1) explain how such input was solicited, (2) summarize the substance of any input received, and (3) explain if and how PG&E incorporated this input into its ultimate proposal in testimony.

ANSWER 013

Yes. PG&E hosts a regular coordination meeting with the CCAS participating in HFP. PG&E shared information with the CCAs on the Stop-Gap rate design in the meeting on 3/26/26 and there was an action item for 3CE to coordinate the rate design feedback from CCAs, however no feedback was provided.

In addition, PG&E did work with CCAs on the original Day Ahead Hourly Real-Time Pricing (DAHRTP) design which was proposed in A.19-11-019 and used the same RNA design. PG&E met with CCAs multiple times, discussed RNA design, and received feedback regarding the flexibility that CCAs desired in setting their own generation RNA values. That same flexibility as discussed in those meetings would still exist in this current proposal.

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Data Response

PG&E Data Request No.:	CalCCA_008-Q016
PG&E File Name:	GRC-2023-PhII_DR_CalCCA_008-Q016
Request Date:	August 18, 2026
Requester DR No.:	008
Requesting Party:	California Community Choice Association
Requester:	Julia Kantor
Date Sent:	September 9, 2026
PG&E Witness(es):	Andrew Au

QUESTION 016

Referring to Exh. PG&E-6 at p. 2-25: Please explain whether a CCA could modify the design of the RNA offered to its customers as part of the HFP 2.0 program design? If so, please explain in what ways a CCA could modify the RNA. If not, please explain why not.

ANSWER 016

As currently proposed, the RNA will be a flat $/kWh adder that may vary by hour. A CCA may modify the values and/or hours as desired.

Yes, a CCA could choose to modify the RNA for the CCA generation rate component offered to its customers by choosing the value of the RNA applied to those customers. Specifically, the RNA could be structured as a flat $/kWh adder that is applied across desired hours.

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PG&E Data Request No.:	CalCCA_008-Q019
PG&E File Name:	GRC-2023-PhII_DR_CalCCA_008-Q019
Request Date:	August 18, 2026
Requester DR No.:	008
Requesting Party:	California Community Choice Association
Requester:	Julia Kantor
Date Sent:	September 9, 2026
PG&E Witness(es):	Andrew Au

QUESTION 019

Referring to Exh. PG&E-6 at p. 2-39: Why is the program administrative cost forecast almost twice that of pricing/billing/customer relationship systems? In PG&E's view, why is this cost breakdown reasonable?

ANSWER 019

One should not try to benchmark the operating cost against the Billing and Customer Relationship Management system costs. The Program Administration budget is comprised of internal FTE labor and external contract resources to enable and support ongoing pilot management and operations. This includes customer enrollment and shadow billing, true-up and on-bill credit processing, ongoing customer inquiries, coordination with CCA and ASP partners, and management of external partner vendors that help PG&E with operations and support of the pilot. These processes are highly labor intensive, requiring a dedicated team of resources who are well-versed in pilot intricacies and who will be responsible for managing enrollment and support for upwards of 16,000 customer services. In contrast, the costs for the Billing and Customer Relationship Management Systems represent capital costs that are primarily vendor-based implementation costs and ongoing Software-as-a-Service (SaaS) fees. Such costs, by their nature, typically represent one-time build costs and incremental support fees. The two categories serve different purposes and are not directly comparable on a one-to-one basis.

Accordingly, the magnitude of Program Administration costs reflects the breadth of functions required to operate, oversee, and maintain the program, while the Billing and CRM Systems category reflects only one component of the overall program infrastructure.

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PG&E Data Request No.:	CalCCA_008-Q021
PG&E File Name:	GRC-2023-PhII_DR_CalCCA_008-Q021
Request Date:	August 18, 2026
Requester DR No.:	008
Requesting Party:	California Community Choice Association
Requester:	Julia Kantor
Date Sent:	September 9, 2026
PG&E Witness(es):	Andrew Au

QUESTION 021

Referring to Exh. PG&E-6 at p. 2-25: Explain whether PG&E considered retaining a modified two-part subscription methodology (e.g., with more frequent subscription updates or a shorter true-up period) as an alternative to full removal. If this was considered and rejected, explain why. If it was not considered, please explain why not.

ANSWER 021

PG&E considered the role of the subscription as part of the HFP rate offering as part of its evaluation of lessons learned from the current HFP pilots. However, PG&E did not pursue a modified subscription design, such as more frequent subscription updates or a shorter true-up period, as part of the proposed HFP 2.0 structure.

As discussed in PG&E's testimony and responses to CalCCA Data Request 008, Question 017, PG&E found that the subscription methodology creates customer comprehension challenges, complicates bill validation, increases administrative burden for PG&E, CCAs, and Automation Service Providers, and can obscure the underlying hourly price signal that HFP is intended to provide. More frequent subscription updates or shorter true-up periods would not eliminate these underlying challenges.

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Data Response

PG&E Data Request No.:	CalCCA_008-Q022
PG&E File Name:	GRC-2023-PhII_DR_CalCCA_008-Q022
Request Date:	August 18, 2026
Requester DR No.:	008
Requesting Party:	California Community Choice Association
Requester:	Julia Kantor
Date Sent:	August 31, 2026
PG&E Witness(es):	Tysen Streib

QUESTION 022

Referring to Exh. PG&E-6 at p. 2-25: Describe what mechanism, if any, will replace the subscription's function of associating bill credits with an actual change in customer load, so as to ensure that credits reflect genuine load shift rather than an incidentally favorable load shape. If no such mechanism exists, please explain why not.

ANSWER 022

Please see the response to GRC-2023-PhII_DR_CalCCA_008-Q009. Credits could be given for incidentally favorable load shape, but this is because the HFP design is more cost-based than TOU rates, as explained in answer to Q009, subpart b.

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Data Response

PG&E Data Request No.:	CalCCA_008-Q023
PG&E File Name:	GRC-2023-PhII_DR_CalCCA_008-Q023
Request Date:	August 18, 2026
Requester DR No.:	008
Requesting Party:	California Community Choice Association
Requester:	Julia Kantor
Date Sent:	September 9, 2026
PG&E Witness(es):	Andrew Au

QUESTION 023

Referring to Exh. PG&E-6 at p. 2-15: Confirm or deny that PG&E does not propose to implement any element of HFP 2.0 (including the RNA and the removal of subscriptions) prior to January 1, 2029, absent an accelerated regulatory or implementation timeline.

ANSWER 023

PG&E is exploring options to accelerate implementation of HFP 2.0, but requires and plans to request regulatory approval for expedited implementation of to implement the certain changes to HFP proposed in PG&E-06, PG&E's Stop-Gap HFP Proposal. Thus, PG&E's implementation timeline is closely linked to when PG&E will receive regulatory approval (as illustrated in Figure 2-1 on p. 2-17 of PG&E-06) and may be updated. As noted in PG&E-06 on p.2-37 line 10, PG&E has requested to submit an implementation advice letter after the Final Decision to update costs and may also present a revised timeline for implementation if warranted in that advice letter.

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Data Response

PG&E Data Request No.:	CalCCA_008-Q024
PG&E File Name:	GRC-2023-PhII_DR_CalCCA_008-Q024
Request Date:	August 18, 2026
Requester DR No.:	008
Requesting Party:	California Community Choice Association
Requester:	Julia Kantor
Date Sent:	September 9, 2026
PG&E Witness(es):	Jahon Amirebrahimi

QUESTION 024

Referring to Exh. PG&E-6 at p. 2-14 to p. 2-16, and p. 2-20 to p. 2-25:

a. Given the concerns PG&E identifies with the current subscription-based HFP 1.0 design, explain why PG&E proposes to continue that design unchanged for an additional year (through 2028) rather than pursuing incremental, interim corrections in 2028.

b. Identify any interim adjustments to the current HFP 1.0 design — short of full HFP 2.0 implementation — that PG&E could feasibly implement during 2028 to address the subscription-related and RNA-related learnings described in this testimony, and explain why any such adjustments were, or were not, considered/proposed.

c. Provide PG&E's estimate of any incremental customer impact (e.g., continued over/underpayment relative to cost of service, or cost shifting) that may result from continuing the current subscription-based HFP 1.0 design through the end of 2028, as compared to implementing corrective changes on an accelerated basis.

d. Explain the relationship between the timing of the Final HFP 1.0 Evaluation Study (expected March 2028) and the RTP Impact Assessment (expected May 2028) (p. 2-15) and PG&E's proposed January 2029 HFP 2.0 implementation date, including whether preliminary findings from those studies could inform an earlier transition.

e. Describe PG&E's position on using 2028 to incorporate HFP 1.0 learnings directly into the design and phased rollout of HFP 2.0, rather than extending HFP 1.0 unchanged through the end of 2028.

ANSWER 024

a. Please refer to PG&E's response to CalCCA Request #008 Question 023.

b. Please refer to PG&E's response to CalCCA Request #008 Question 023.

c. PG&E does not have the information requested by this data request. Both rate designs are structured to be revenue neutral as a whole, and PG&E does not have estimates of various impacts on customers on a more granular level. PG&E has not developed any analyses for that purpose and performing such an analysis would be burdensome and speculative. On these grounds, PG&E objects to this question as burdensome and speculative.

   Without waiving the foregoing objection, PG&E responds as follows. PGE&E believes that both the current subscription design and the revised changes are close to PG&E's cost of service and that one design is not necessarily superior to the other for that purpose. PG&E's desire to remove subscription is for customer experience reasons, not for cost accuracy.

d. The HFP 1.0 final evaluation and RTP Impact Assessment serve complementary purposes. The HFP 1.0 final evaluation, due March 1, 2028, is an ex-post assessment of observed pilot performance, including load response, bill impacts, system benefits, costs, customer experience, and pilot processes. The RTP Impact Assessment, due May 1, 2028, is a forward-looking, scenario-based analysis of potential RTP adoption, load response, system impacts, and cost-effectiveness under broader deployment scenarios. PG&E proposed January 2029 as the target for implementing HFP 2.0 to provide time following the Commission's Final Decision to complete the required rate, billing, operational, vendor, and customer-transition activities. PG&E's proposal also permits an earlier transition if regulatory and implementation timelines allow.

   To the extent sufficiently developed findings become available before the final reports, PG&E may consider them in ongoing planning. However, PG&E cannot presently confirm that preliminary findings would support an earlier transition. That determination would depend on the nature and reliability of the findings, the Commission's authorization, and operational feasibility.

e. PG&E supports incorporating available HFP 1.0 learnings into the design and implementation of HFP 2.0. PG&E would consider incorporating additional HFP 1.0 learnings during 2028 if regulatory approvals for such changes were received on a timeline that enabled accelerated changes where feasible.

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PG&E Data Request No.:	CalCCA_008-Q025
PG&E File Name:	GRC-2023-PhII_DR_CalCCA_008-Q025
Request Date:	August 18, 2026
Requester DR No.:	008
Requesting Party:	California Community Choice Association
Requester:	Julia Kantor
Date Sent:	August 25, 2026
PG&E Witness(es):	Neda Assadi

QUESTION 025

Referring to Exh. PG&E-6 at p. 4-2: Describe in detail what specific customer-level or program-level information from CCAs (or other third party demand response or incentive program administrators) would be sufficient for PG&E to prevent double compensation under HFP, including the frequency (e.g., monthly, per dispatch event, or per true-up cycle) at which such information would need to be provided.

ANSWER 025

Today, PG&E prevents double compensation under Hourly Flex Pricing (HFP) at the time of enrollment through dual participation enrollment verifications.

Participation in supply-side DR programs is well tracked in the California Independent System Operator (CAISO) Demand Response Registration System (DRRS), across all entities registering customers for participation in CAISO wholesale market DR resources (IOUs, CCAs, DRPs, etc.). Registration in DRRS is deemed to be participation in a supply side program.[1] If a customer enrolled in HFP seeks to later enroll in a supply-side DR program, the CAISO DRRS process requires PG&E to verify that the customer is eligible, and PG&E will reject the customer from participating in the CAISO wholesale market due to the dual participation prohibition. If a customer enrolled in HFP seeks to later enroll in a PG&E program (supply side or load modifying) where dual participation is prohibited, PG&E will reject the customer from participating in the conflicting program due to the dual participation prohibition. PG&E will not provide the name of the program/entity the customer is enrolled with to the entity seeking to enroll the customer in the Expanded Pilots, in compliance with existing privacy requirements.[2]

[1] This PG&E dual participation check includes the CEC DSGS Option 2, which is the Incremental Market-Integrated Demand Response Capacity Pilot and requires participation in the wholesale market.

[2] This does not apply if the customer is seeking to enroll itself, or if the customer has already authorized the release of such data to the third party.

To implement dual participation prohibitions on non-PG&E event-based load-modifying programs and for CCAs participating in HFP, PG&E is working with CCAs to prevent dual participation where prohibited, both where the CCA is the entity registering the customer, and where it is not. Today, PG&E exchanges Excel files with CCAs every two weeks (typically Wednesdays), with CCAs asked to respond within 2 to 5 business days to verify enrollment eligibility.

Any future processes that would prevent double compensation in programs that are permitted is highly dependent on the program design and compensation structures. At minimum, program-specific requirements include:

- Program name, administrator/DR provider, and grid service(s) provided
- Incentive structure (capacity vs. energy vs. one-time payment/credit)
- Event triggers and dispatches
- Type of baseline used to calculate performance
- Rules for impact allocation (if split between two programs) used for settlement and resource planning

Customer-specific requirements include:

- Service agreement IDs
- Start date and end date of participation
- Customer performance per event
- Event-specific payment/credit or one-time payment/credit

For HFP today, which permits dual participation with Critical Peak Pricing (CPP) programs like SmartRate and Peak Day Pricing and the Emergency Load Reduction Program (ELRP) pilot, PG&E addresses double compensation for ELRP at the time of the HFP Bill Credit assessment/true-up using a simple formula that reduces HFP bill credits by the incentives received under the other program.[3] This process minimizes operational changes to the existing ELRP processes and allows for one-time assessment at the time of shadow bill true-up.

[3] See PG&E Advice 7223-E-B.

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Data Response

PG&E Data Request No.:	CalCCA_008-Q026
PG&E File Name:	GRC-2023-PhII_DR_CalCCA_008-Q026
Request Date:	August 18, 2026
Requester DR No.:	008
Requesting Party:	California Community Choice Association
Requester:	Julia Kantor
Date Sent:	August 25, 2026
PG&E Witness(es):	Neda Assadi

QUESTION 026

Referring to Exh. PG&E-6 at p. 4-2: Describe any data-sharing protocols, confidentiality protections, or system changes PG&E has evaluated, or believes would need to be developed, to receive CCA program participation or payment data sufficient to inform shadow-bill calculations while protecting competitively sensitive CCA program information.

ANSWER 026

PG&E has implemented an Excel file-sharing process for HFP as stated in the response for Question 25. PG&E has not evaluated any other data-sharing protocols, confidentiality protections, or system changes specific to HFP CCA program participation. PG&E has existing data-sharing protocols and confidentiality protections typically described within non-disclosure agreements.

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Data Response

PG&E Data Request No.:	CalCCA_008-Q027
PG&E File Name:	GRC-2023-PhII_DR_CalCCA_008-Q027
Request Date:	August 18, 2026
Requester DR No.:	008
Requesting Party:	California Community Choice Association
Requester:	Julia Kantor
Date Sent:	September 9, 2026
PG&E Witness(es):	Tysen Streib and Andrew Au

QUESTION 027

a. If PG&E offered a delivery-only RTP rate (i.e., a rate limited to the distribution/delivery component, excluding the generation-related RNA or commodity component), describe how such a rate would need to be structured to allow a CCA to offer its own generation-side RTP rate in coordination with PG&E's delivery-only rate, and identify any technical, billing, or regulatory barriers to this approach.

b. Could PG&E offer a delivery-only RTP rate that doesn't need to be paired with a Generation RTP rate (i.e., a delivery RTP rate that can be paired with a customer's normal Otherwise Applicable Tariff)? Does PG&E have any plans to consider such a rate option?

c. Could PG&E offer a generation-only RTP rate that doesn't need to be paired with a delivery RTP rate (i.e., a generation RTP rate that can be paired with a customer's normal Otherwise Applicable Tariff)? Does PG&E have any plans to consider such a rate option?

ANSWER 027

a. PG&E can offer a delivery-only RTP rate which would allow a CCA to offer its own generation-side RTP rate. PG&E's preference is to provide the same options as was offered to CCA's in the HFP 1.0 CCA agreement, including:

Generation-Side RTP Options for CCAs

1. Limited configuration to PG&E's proposed rate design
    - Modify MEC (Marginal Energy Cost) coefficients, and/or
    - Modify MGCC (Marginal Generation Capacity Cost) coefficients, and/or
    - Modify RNA (e.g., discount)
    - Requires the CCA to provide pricing parameters, comply with implementation SLAs, and complete testing.

- CCA is responsible for associated implementation and maintenance costs.

2. Fully Customized Generation RTP

- CCA-specific rate and pricing designs.
- CCA is responsible for implementation and maintenance costs.

Technical Considerations

These options assume the CCAs use the same Shadow Billing and Pricing Engine systems utilized by PG&E for its Stop-Gap program. Implementation would require coordination with the RTP pricing platform vendor for detailed evaluation, contracting, system configuration, testing, and ongoing support and operations.

b. Yes, subject to Commission approval, PG&E has the ability to offer a delivery-only RTP rate without requiring participation in a corresponding generation RTP rate. PG&E is actively evaluating this design option, particularly for unbundled customers served by LSEs that do not provide a generation RTP offering, to facilitate broader customer access to RTP participation.

c. No, PG&E has no plans to consider offering a generation-only RTP rate. The California Public Utilities Commission required PG&E to offer all customer classes an RTP rate with both generation and delivery portion as contained in Energy Commission's Load Management Standards. PG&E does not believe that it would be worthwhile maintaining a separate generation-only version of the rate alongside the CPUC mandated version.

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Data Response

PG&E Data Request No.:	CalCCA_009-Q004
PG&E File Name:	GRC-2023-PhII_DR_CalCCA_009-Q004
Request Date:	September 25, 2026
Requester DR No.:	009
Requesting Party:	California Community Choice Association
Requester:	Julia Kantor
Date Sent:	October 9, 2026
PG&E Witness(es):	Andrew Au

QUESTION 004

Referring to PG&E's response to CalCCA Data Request 8.19:

a. Please provide the FTE counts and labor rates assumed to support the Program Administration budget.

b. Please provide the estimate for external contractors and number of hours assumed in the Program Administration budget.

ANSWER 004

a. The Program Administration labor estimate was developed using a standard assumption of 2,080 hours per full-time equivalent (FTE) per year. The FTE estimates comprise both PG&E personnel and external contractor resources.

   The staffing assumptions reflected in the workpaper - *GRC-2023-PhII_DR_CalAdvocates_034-Q001Atch01* are shown below.

Labor Component	2028 FTE	2029 FTE	2030 FTE	2031 FTE
Program Management	2.0	2.0	2.0	2.0
Business Product Architect	2.0	2.0	2.0	2.0
Project Management	2.0	2.0	2.0	2.0
Customer Operations & Analytics*	2.0	3.0	4.0	5.0

**Customer Operations & Analytics is the only function that increases over time, reflecting additional resources added as projected enrollment levels increase.*

The corresponding budgeted hours are:

Labor Component	2028 Hours	2029 Hours	2030 Hours	2031 Hours
Program Management	4,160	4,160	4,160	4,160
Business Product Architect	4,160	4,160	4,160	4,160
Project Management	4,160	4,160	4,160	4,160
Customer Operations & Analytics	4,160	6,240	8,320	10,400

The workpaper uses the following labor rates for estimation purposes:

Resource Type	Hourly Rate
Contractor 1	$150/hour
Contractor 2	$150/hour
Contractor 3	$125/hour
Contractor 4	$225/hour
PG&E Employee	$158/hour (2028), $164/hour (2029), $171/hour (2030), $179/hour (2031)

The Customer Operations & Analytics function is the only Program Administration labor category that scales with projected enrollment growth. Adds one incremental resource as projected enrollment grows beyond approximately 7,000, 9,000, and 12,000 enrolled service agreements, resulting in staffing growth from 2 FTEs in 2028 to 5 FTEs in 2031. The Program Management, Business Product Architect, and Project Management functions remain at 2 FTEs each year because they support ongoing program governance, implementation oversight, solution management, stakeholder coordination, vendor management, budgeting, and operational administration activities that are not directly tied to enrollment volumes.

b. The Program Administration budget for use of external contractor resources at $150/hour, $125/hour and $225/hour rates is presented below.

   The workpaper presents 2,080 hours per FTE per year. Based on the staffing assumptions reflected in the Program Administration budget, the external contractor hours are as follows:

Labor Component	2028 Hours	2029 Hours	2030 Hours	2031 Hours
Program Management (2 contractors)	4,160	4,160	4,160	4,160
Business Product Architect (1 contractor)	2,080	2,080	2,080	2,080

Labor Component	2028 Hours	2029 Hours	2030 Hours	2031 Hours
Project Management (no contractors estimated)	0	0	0	0
Customer Operations & Analytics (contractors)	2,080	4,160*	6,240*	8,320*

**Customer Operations & Analytics is the only function that increases over time, reflecting additional resources added as projected enrollment levels increase.*

Total estimated external contractor hours assumed in the Program Administration budget are therefore:

Year	Estimated Total Contractor Hours
2028	8,320
2029	10,400
2030	12,480
2031	14,560

For the full 2028-2031 period, the Program Administration budget assumes a total of 45,760 external contractor hours. These hours support Program Management, Business Product Architect, Project Management, and Customer Operations & Analytics activities. Customer Operations & Analytics is the only function that increases over time, reflecting additional resources added as projected enrollment levels increase.

The corresponding Program Administration labor budget for external contractors is approximately:

- Program Management: $2.50 million
- Business Product Architect: $1.87 million
- Project Management: $0 (no contractors estimated)
- Customer Operations & Analytics: $2.6 million

PG&E estimates approximately $6.97 million in external contractor labor costs as part of the Program Administration budget for the 2028-2031 period. This estimate reflects the level of contractor resources necessary to support program management, business architecture, project management, and customer operations functions required to administer and operate the proposed HFP program.

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Data Response

PG&E Data Request No.:	CalCCA_010-Q001
PG&E File Name:	GRC-2023-PhII_DR_CalCCA_010-Q001
Request Date:	October 21, 2026
Requester DR No.:	010
Requesting Party:	California Community Choice Association
Requester:	Julia Kantor
Date Sent:	October 23, 2026
PG&E Witness(es):	Andrew Au

QUESTION 001

Referring to PG&E's response to CalCCA Data Request 8.01:

a. Please provide the number of enrolled bundled customers versus enrolled unbundled customers in PG&E's HFP pilots to date.

b. Please provide the amount of enrolled bundled load versus enrolled unbundled load in PG&E's HFP pilots to date.

ANSWER 001

a. Data as of 10/21/2026 for HFP Pilot 1 and HFP Pilot 2.

Pilot	Service Type	Count of enrolled SA's	Enrolled Load (MW)
HFP Pilot 1 (Ag)	Bundled	1,232	93.03
	Unbundled	50	6.86
HFP Pilot 2 (Res, C&I)	Bundled	177	11.75
	Unbundled	767	48.68
	Total	2,226	160.32

b. Refer a.

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11/02/26
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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 FINAL 2028 PLANNING RESERVE MARGIN STUDY AND PROPOSALS

Leanne Bober,
Director of Regulatory Affairs and
Deputy General Counsel
Lauren Carr,
Deputy Director of Regulatory Affairs
Eric Little,
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ATTACHMENT A CALIFORNIA COMMUNITY CHOICE ASSOCIATION FINAL 2028 PLANNING RESERVE MARGIN STUDY

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 FINAL 2028 PLANNING RESERVE MARGIN STUDY AND PROPOSALS

California Community Choice Association[1] (CalCCA) submits these proposals pursuant to the *Assigned Commissioner's Scoping Memo and Ruling,*[2] dated December 12, 2025; *Assigned Commissioner's Amended Scoping Memo and Ruling,*[3] dated August 25, 2026; and *Administrative Law Judge's Ruling Modifying Track 2 Schedule*[4] (Ruling), dated September 25, 2026.

I. INTRODUCTION

CalCCA appreciates the opportunity to submit its Final 2028 Planning Reserve Margin (PRM) Study (CalCCA's Final 2028 PRM Study) and proposals. CalCCA applauds the California Public Utilities Commission (Commission) for providing the opportunity for parties,

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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, 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, Valley Clean Energy, and WestLight Energy.

[2] *Assigned Commissioner's Scoping Memo and Ruling*, Rulemaking (R.) 25-10-003 (Dec. 12, 2025), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M590/K884/590884355.PDF.

[3] *Assigned Commissioner's Amended Scoping Memo and Ruling*, R.25-10-003 (Aug. 25, 2026), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M615/K874/615874564.PDF.

[4] *Administrative Law Judge's Ruling Modifying Track 2 Schedule*, R.25-10-003 (Sept. 25, 2026), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M620/K565/620565731.PDF.

along with Energy Division staff, to conduct thorough analysis and have robust conversations about how to set the Resource Adequacy (RA) PRM. Loss-of-Load Expectation (LOLE) modeling, used in CalCCA's, Energy Division's, and SCE's PRM analyses, accounts for the complex interactions among load variability, generator outages, weather conditions, resource availability, and the diversity of resources on the system. It also captures how these factors affect reliability across different hours, seasons, and operating conditions. This complexity requires iterative analysis, review, and discussion among Energy Division and parties to ensure a develop a shared understanding of the methodology and establish a PRM that meets the Commission's reliability standard.

CalCCA's Final 2028 PRM Study, attached hereto as Attachment A, evaluates how the capacity needed to meet the Commission's 0.1 LOLE reliability standard under eight different PRM selection criteria, four of which incorporate cost minimization. Each of the eight PRM selection criteria utilize risk-reserve curves for each month developed from pairing many different portfolios' accredited capacity with their LOLE. The cost-minimizing criteria use the risk-reserve curves to solve an optimization problem that determines how much accredited capacity needs to be shown in each month to meet the 0.1 LOLE reliability standard at least cost. These criteria recognize that the PRM should achieve an established reliability standard while minimizing the cost of maintaining that level of reliability.

CalCCA's Final 2028 PRM Study maintains the core design elements from CalCCA's August 14, 2026, Draft 2028 PRM Study,[5] including generating monthly risk-reserve curves using the same data and tools employed in Energy Division's PRM study process. Through 12

[5] *California Community Choice Association's Track 2 Loss of Load Expectation Study and PRM Proposals*, R.25-10-003 (Aug. 14, 2026) (CalCCA Draft 2028 PRM Study), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M614/K484/614484383.PDF.

different risk-reserve cases, CalCCA's Final 2028 PRM Study explores key uncertainties that impact the risk-reserve curves. It also reflects updates based upon the feedback and questions received from Energy Division and parties in September 2, 2026, informal comments and the September 15, 2026, workshop (Workshop),[6] including using the UCAP EFORd +Ambient Calibration Workbook to align with 2028 resource accreditation rules.[7]

CalCCA's Final 2028 PRM Study overall achieves three objectives by: (1) providing a pathway to lower electricity costs for customers while maintaining reliability; (2) linking PRMs to a transparent and consistent process; and (3) generates datasets, namely risk-reserve curves, that enable stakeholders to evaluate a wide range of alternative PRM selection criteria. The Study demonstrates the process for establishing PRM selection criteria that can be used to inform the PRM when there are multiple options for setting PRMs that produce the same level of reliability. Using this approach, CalCCA's analysis demonstrates that grouping the peak summer month PRMs (July-September) and high-variability months (*e.g.,* April, May) results in higher PRMs in the peak months and higher RA cost, without improving reliability relative to other options for setting the PRM.

With this information, the results of CalCCA's Final 2028 PRM Study confirm CalCCA's primary recommendation: the Energy Division should adopt CalCCA's approach to generating monthly risk-reserve curves and comparing PRMs stemming from different selection criteria in its PRM studies. It also highlights that different modeling assumptions, such as import

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6 *R.25-10-003 Track 2 Workshop* (Sept. 15, 2026), https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/8-17-2026-track-2/r2510003-workshop-on-lole-studies20260915version-2.pdf.

7 September 15, 2026, Workshop: Energy Division Updated PRM Results, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/8-17-2026-track-2/prm-results-20260915-workshop.zip.

assumptions, can significantly alter the monthly risk-reserve curves and associated PRMs and should be further developed in future PRM studies. In summary and based on CalCCA's Final 2028 PRM Study results, the Commission should:

- Adopt a PRM study methodology that achieves an established reliability standard while minimizing RA costs by developing monthly risk-reserve curves and using CalCCA's RA cost-minimizing PRM criteria as affordability benchmarks;
- Adopt monthly PRMs that separate the peak summer months from high variability spring months based on the CAISO's target LOLE distribution using CalCCA's Case B assumptions, resulting in monthly PRMs that range from 4-16 percent across most months, with PRMs as high as 16-31 percent only in April and May, respectively;
- Use Energy Division's import assumptions and adopt a future workshop process to consider alternative assumptions for future studies; and
- Remove the effective PRM and instead adopt a single set of PRMs for all LSEs.[8]

II. THE PRM STUDY METHODOLOGY SHOULD ACHIEVE AN ESTABLISHED RELIABILITY STANDARD WHILE MINIMIZING RA COSTS

The Commission should adopt CalCCA's proposed PRM study methodology to allow the Commission to set the PRM in a manner that achieves an established reliability standard while minimizing RA costs. This methodology was used in CalCCA's Final 2028 PRM Study to inform the recommendations for the 2028 PRMs in Section III below. Key elements of CalCCA's proposed study methodology are: (1) the development of monthly risk-reserve curves to demonstrate the relationship between the achieved reserve margin and the risk of not having sufficient resources to meet demand; and (2) using the risk-reserve curves to find PRMs that all meet a LOLE of 0.1 events/year using PRM selection criteria, including criteria that minimize RA costs.

[8] CalCCA may include changes or additions to these recommendations in its November 20, 2026, opening comments, if necessary, informed by final LOLE studies filed by other parties.

A. CalCCA's Proposed Methodology for Developing Monthly Risk-Reserve Curves Should Be Adopted

The Commission should adopt CalCCA's methodology for developing monthly risk-reserve curves to demonstrate the relationship between the achieved reserve margin - the amount by which the contracted accredited capacity exceeds the forecasted peak demand - and the risk of not having sufficient resources to meet demand. These risk-reserve curves should be used in conjunction with PRM selection criteria, described in Section II.B. below, to select PRMs that best maintain reliability at the lowest cost to customers.

During the Workshop, it became clear that several key modeling assumptions remain uncertain. Rather than developing a single set of monthly risk-reserve curves, CalCCA's Final 2028 PRM Study includes 12 different risk-reserve cases to demonstrate how different sets of assumptions impact risk and reserves and lead to different sets of curves. The cases address three areas: (1) the source of the peak demand for reserve calculations; (2) the portion of the Baseline that remains uncontracted and therefore unable to contribute to CAISO reliability; and (3) treatment of economic imports (non-RA imports) in probabilistic reliability modeling and reserve calculations.

CalCCA's Final 2028 PRM Study demonstrates the process the Commission should use to quantify tradeoffs between different PRM selection criteria. This approach provides a pathway to lower electricity costs for customers while maintaining reliability, links PRMs to a transparent and consistent process, and generates datasets, namely risk-reserve curves, that enable stakeholders to evaluate a wide range of alternative PRM selection criteria. The Commission should adopt CalCCA's approach to generating monthly risk-reserve curves and comparing PRMs resulting from different selection criteria for its PRM studies going forward.

B. RA Cost-Minimizing Selection Criteria Should Be Used as Affordability Benchmarks to Inform the PRM

The Commission should use PRMs found using RA cost-minimizing criteria as an affordability benchmark to inform PRM proposals. After developing risk-reserve curves, PRM selection criteria are needed to select specific PRMs. As described in Section III.A, below, Energy Division's previous PRM analysis reflects two selection criteria: (1) equivalent PRMs across all months (Annual); and (2) equivalent PRMs across the months of May-September with all unmet demand concentrated in those months and a separate PRM in all other months (Seasonal2). These selection criteria do not result in the most cost-effective PRMs meeting the LOLE of 0.1 events/year reliability standard. Instead, the Commission should benchmark the cost of their proposed PRMs against PRMs resulting from CalCCA's RA cost-minimizing selection criteria, which elect monthly PRMs in a way that minimizes RA costs while meeting a LOLE of 0.1 events/year.

III. MONTHLY PRMS BASED ON THE CAISO'S TARGET LOLE DISTRIBUTION SHOULD BE ADOPTED FOR 2028

The Commission should adopt monthly PRMs based on the "CAISOTargetLOLE" selection criteria for the 2028 RA program.[9] This recommendation is based on the results of CalCCA's Final 2028 PRM Study using the methodology recommended in Section II. above, which finds that: (1) assuming equivalent PRMs across May through September results in higher RA costs than alternative PRM structures that achieve the same level of reliability; and (2) establishing separate PRMs for peak summer and high-variability spring months can reduce RA costs by 4.0 to 5.7 percent under modeling assumptions consistent with Case B. The resulting

[9] The "CAISOTargetLOLE" selection criteria, defined in CalCCA's Final 2028 PRM Study, sets the monthly PRMs to match CAISO Target LOLE distribution used to develop its Default PRM and Qualifying Capacity values. *See* CalCCA's Final 2028 PRM Study, at 15-16.

PRMs for 2028 would range from 4-15 percent across most months with PRMs as high as 17-28 percent only in April and May, as shown in Figure 1, below.[10]

A. Separate Peak-Summer PRMs (July–September) from PRMs in High-Variability Months Such as April and May

The Commission should adopt separate PRMs for peak-summer months and high-variability spring months. Energy Division's Draft PRM Study evaluates a two-season PRM with equivalent PRMs across the months of May-September and a separate PRM for all other months (Seasonal2). Assuming equivalent PRMs across May through September results in higher RA costs than alternative PRM structures that achieve the same level of reliability.[11]

CalCCA's analysis demonstrates that there is no clear justification for grouping peak summer months (July–September) with high-variability spring months (*e.g.,* April and May). Rather, the analysis finds that the lowest-cost PRM structures avoid grouping high-variability months, such as May, with high-cost peak summer months, such as September.[12] Applying the same PRM across these months unnecessarily increases PRMs during peak summer months, raising RA costs without providing additional reliability benefits. The Commission should therefore establish separate PRMs for peak summer and high-variability spring months to achieve its reliability standard at an affordable cost.

B. Set 2028 PRMs Consistent with the CAISO Target LOLE Distribution, Using Case B Assumptions

The Commission should use the CAISOTargetLOLE PRM selection criteria with risk-reserve curves from Case B to set the 2028 PRMs. These assumptions allow Energy Division to continue to identify loss-of-load events by removing perfect capacity, consistent with its existing

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10 CalCCA Final LOLE Study, at 33-34.
11 *Ibid.*
12 *Ibid.*

methodology, and will result in monthly PRMs that range from 4-15 percent across most months with PRMs as high as 16-27 percent only in April and May, as shown in Figure 1, below.

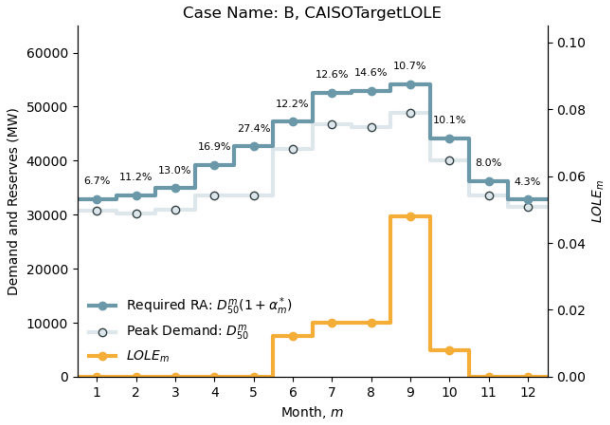


Figure 1. CalCCA recommends 2028 PRMs selected using the CAISOTargetLOLE criteria with risk-reserve curves from Case B.

With these PRMs, 80 percent of the LOLE is concentrated in July, August, and September, the months with the highest RA requirements - exceeding 52 gigawatts (GW). The concentration of LOLE in these months allows the PRMs to stay between 10.7 to 14.6 percent, or 2.8 to 6.7 percentage points lower than it would have otherwise been with an Annual or Seasonal2 PRM. Using the CAISOTargetLOLE selection criteria to set the PRM can reduce RA costs by 4.0 to 5.7 percent under modeling assumptions consistent with Case B.[13]

The resulting PRMs are significantly higher in April and May than they would have been under an Annual or Seasonal2 PRM. However, the moderate 1-in-2 peak loads in the Spring months mean the RA requirements in those months remain below 44 GW. Historical observations of economic imports in April and May suggest that the RA requirements in those months could be lower without sacrificing reliability. Additionally, April and May PRMs were less than 18 percent in April and May of 2025 and 2026 without observed reliability issues.

[13] CalCCA Final 2028 PRM Study, at 33-34.

However, until further data and analysis are available, it is prudent to recommend April and May PRMs that are high enough to avoid unmet energy under the assumptions in Case B.

The combination of moderate PRMs and low 1-in-2 peak demand in the months of November through March keep RA requirements in those months below 37 GW. This period of lower RA requirements creates a contiguous five-month period suitable for planned maintenance of generating resources, without detrimental impacts to reliability. Overall, CalCCA's recommended PRMs achieve significant reductions in consumer costs of complying with RA requirements while still ensuring that the system has sufficient resources to meet a LOLE of 0.1 events/year.

IV. ENERGY DIVISION'S IMPORT ASSUMPTIONS SHOULD BE USED UNTIL A WORKSHOP PROCESS IS CONDUCTED TO DEVELOP ALTERNATIVE ASSUMPTIONS

The Commission should adopt Energy Division's proposed import assumptions for setting the 2028 PRMs and commit to holding additional workshops to further develop import RA assumptions for future PRM studies. Draft studies from CalCCA, SCE, and Energy Division used differing import assumptions without a clear recognition of the implications for PRMs. CalCCA's Final 2028 PRM Study further investigates the impacts of different import assumptions on PRMs and shows that the impacts can be significant. Figure 10 in the CalCCA's Final 2028 PRM Study shows that PRMs can vary, in the most extreme months of April and May, by more than 25 percentage points across different assumptions on import accreditation. While differences in the PRMs are much smaller in the critical months of July through September, only 7 percentage points, these months have historically had the tightest RA supply and highest RA costs. Historical relationships between the capacity of imports shown in RA filings and the observed hourly imports during actual system operations demonstrate that allowing imports to exceed shown RA import capacity, particularly in non-summer months,

reflect likely outcomes.[14] Cases that allow some degree of imports in excess of shown RA imports, including the Energy Division's assumptions in Case B, result in lower PRMs. Alternatively, the most conservative assumptions, used in Case D and Case E, deviate from observed system operations.[15] The Commission should therefore adopt Energy Division's assumptions as a reasonable middle ground and interim solution for import assumptions used for setting 2028 PRMs.

Energy Division should host workshops on import assumptions prior to the next PRM study to further develop the import assumptions for future PRMs. The workshops should directly consider the question of what role energy-only economic imports should play in reliability modeling, especially as the system continues to both better integrate with neighboring regions and incorporate a greater share of energy-limited resources, like battery storage.

V. THE EFFECTIVE PRM SHOULD BE REMOVED

CalCCA continues to recommend that the Commission remove the effective PRM, with no changes to its August 14, 2026, Proposal.[16] The Commission should remove the effective PRM because it: (1) adds demand to the RA market, driving up costs when RA supply is tight; (2) allows the Commission to deviate from the 0.1 LOLE standard in an arbitrary manner; (3) creates an uneven playing field across LSEs by directing the IOUs to procure the effective PRM requirement and allocating the costs of the procurement to all LSEs; (4) does not allow the CAISO to backstop for RA deficiencies; and (5) encroaches on CCA procurement autonomy authorized by statute.

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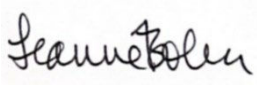
14 CalCCA's Final 2028 PRM Study, at 11-12.
15 *Ibid.*
16 August 14, 2026, Proposal, at 19-22.

CalCCA clarifies its recommendation for the Commission to "establish a single PRM for all LSEs," rather than retaining the effective PRM, in response to a question received during the Workshop. If the Commission adopts monthly or seasonal PRMs rather than an annual PRM, the Commission should adopt *a single set* of monthly or seasonal PRMs for all LSEs. This proposal is not intended to limit the Commission to one PRM for the entire year. Instead, it is intended to apply a uniform PRM or set of PRMs to all LSEs.

VI. CONCLUSION

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

Respectfully submitted,



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CALIFORNIA COMMUNITY CHOICE ASSOCIATION

November 2, 2026

ATTACHMENT A
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
FINAL 2028 PLANNING RESERVE MARGIN STUDY AND PROPOSALS

CALIFORNIA COMMUNITY CHOICE ASSOCIATION
FINAL 2028 PLANNING RESERVE MARGIN STUDY

ANDREW MILLS, Director of Data Analytics
DESIK SOMASUNDARAM, Senior Data Analyst
November 2, 2026

CALIFORNIA COMMUNITY CHOICE ASSOCIATION FINAL 2028 PLANNING RESERVE MARGIN STUDY

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November 2, 2026

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1. Motivation and Context

The California Public Utilities Commission (CPUC) requires load-serving entities (LSEs) contract with resources sufficient to meet forecasted customer demand on peak days plus a planning reserve margin (PRM). The Energy Division develops tools, data, and studies to recommend a PRM for 2028 and 2029 with the goal of meeting a reliability target of one loss-of-load event in ten years, or equivalently a loss-of-load expectation (LOLE) of 0.1 events/year. To elicit robust discussion and perspectives, the CPUC invited stakeholders to conduct their own PRM studies in parallel to the Energy Division's study.[1] CalCCA's study relies on tools and data provided by the Energy Division, along with CalCCA's probabilistic reliability model in PLEXOS, to recommend PRMs that meet the LOLE of 0.1 events/year.

In the CPUC's Resource Adequacy (RA) program, the role of the PRMs is to determine the portion of online resources that must be available to contribute to reliability. The set of resources expected to be online in 2028, called the Baseline, may not be fully available throughout the year due to maintenance outages or contracts to supply power outside of the California Independent System Operator (CAISO) balancing authority area (BAA). An RA contract ensures that a resource is available and offers its generating capability to the CAISO market through an associated must-offer obligation.

The RA program requires LSEs to show RA contracts for each month of the year. Even though the 0.1 LOLE reliability target is defined as an annual metric, the portion of the Baseline that must be contracted for RA varies by month due to the monthly variability in forecasted peak load and resource accreditation. The process of setting PRMs answers the question: how much accredited capacity of the Baseline should be shown in each month for the system to be reliable (LOLE $\leq$ 0.1)?

In regions with an annual RA program, a single annual PRM, and an annual reliability target, the process of setting the PRM is straightforward. Reductions or additions of resources to the Baseline decrease or increase reliability, respectively. Only one choice of accredited capacity corresponds with a LOLE of 0.1 events/year; only one choice of PRM exactly meets the reliability target.

In the Commission's monthly RA program, the month-to-month variation in peak demand and accredited capacity means that there is no one, unique choice of monthly shown capacity that corresponds with an annual LOLE of 0.1 events/year. Many combinations of monthly PRMs yield a reliable system. This means additional criteria are necessary to select PRMs.

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[1] *Assigned Commissioner's Amended Scoping Memo and Ruling*, Rulemaking (R.) 25-10-003 (Aug. 25, 2026), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M615/K874/615874564.PDF; *Administrative Law Judge's Ruling Modifying Track 2 Schedule*, R.25-10-003 (Sept. 25, 2026), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M620/K565/620565731.PDF.

Energy Division's previous PRM studies have implicitly included two criteria to recommend PRMs for the monthly RA program. *First*, Energy Division previously assumed an annual PRM,[2] which implicitly requires equivalent monthly PRMs. Requiring equivalent monthly PRMs, coupled with the annual reliability target, allows Energy Division to identify a unique annual PRM. *Second*, Energy Division's 2028 Draft 2028 PRM study[3] assumes a seasonal PRM that can vary between summer and non-summer months, with all of the loss-of-load events occurring in the summer months. This, along with the choice of which months are summer and which are non-summer, allows Energy Division to identify a unique seasonal PRM.

The Energy Division's PRM selection criteria are not exhaustive. CalCCA's Inputs and Assumptions document[4] and Draft 2028 PRM Study[5] describe a process for selecting PRMs that minimize RA costs while still achieving the target level of reliability. Additional research and discussions with stakeholders raised additional PRM selection criteria that we evaluate in this study. CalCCA's list of PRM selection criteria is broader than Energy Division's but remains a subset of all the possible criteria.

Key to evaluating any PRM selection criterion is the concept of risk-reserve curves.[6] A risk-reserve curve shows the relationship between achieved reserve margin—the amount by which the contracted accredited capacity exceeds the forecasted peak demand—and the risk of not having sufficient resources to meet demand, resulting in a loss-of-load event. With a monthly RA program, the relationship between achieved reserve margin and risk of loss-of-load events differs by month, requiring twelve monthly risk-reserve curves. Once these curves are specified, it is simple to find monthly PRMs that meet different PRM selection criteria while meeting an annual LOLE of 0.1 events/year.

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[2] Energy Division, *Loss of Load Expectation Study for 2026 Including Slice of Day Tool Analysis: Recommendation for Slice of Day Planning Reserve Margin*,(July 19, 2024) (Energy Division's 2026 PRM Study), at 34, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/slice-of-day-compliance-materials/2026_lole_final_report_07192024.pdf.

[3] Energy Division, *Loss of Load Expectation Study for 2028: Draft Results* (August 14, 2026) (Energy Division's Draft 2028 PRM Study), at 21, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/8-17-2026-track-2/energy-division-draft-2028-lole-study.pdf.

[4] *California Community Choice Association's Alternative Inputs & Assumptions Document in Response to Administrative Law Judge's Ruling Modifying 2028 Loss of Load Expectation Study Schedule*, R.25-10-003 (June 5, 2026) (CalCCA I&As), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M608/K216/608216359.PDF.

[5] *California Community Choice Association's Track 2 Loss of Load Expectation Study and PRM Proposals*, R.25-10-003 (Aug. 14, 2026) (CalCCA Draft 2028 PRM Study), https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=614484383.

[6] *See* Brattle and Astrape, *Resource Adequacy Requirements: Reliability and Economic Implications* (2013), at 3-5 (providing a more detailed discussion on determining system reliability as a function of planning reserve margin), https://www.ferc.gov/sites/default/files/2020-05/02-07-14-consultant-report.pdf.

CalCCA's Input and Assumptions and Draft 2028 PRM Study describes a systematic approach to generating monthly risk-reserve curves using the same data and tools employed in the Energy Division's PRM study process. At the time of publishing CalCCA's Draft 2028 PRM Study, key data and assumptions, affecting both the risk and reserve calculations, remained open-ended. These data and assumptions can significantly shift and change the shape of risk-reserve curves. As such, CalCCA focuses the Final 2028 PRM Study on two areas. *First*, we evaluate how key uncertainties impact the risk-reserve curves. The uncertainties include:

- The source of the peak demand for reserve calculations;
- The composition of the portion of the Baseline that remains uncontracted and therefore unable to contribute to CAISO reliability; and
- Treatment of economic imports (non-RA imports) in probabilistic reliability modeling and reserve calculations.

Second, we use the risk-reserve curves to find PRMs using several different PRM selection criteria that all meet a LOLE of 0.1 events/year. CalCCA's analysis finds that the lowest cost PRMs avoid grouping high variability months, such as May, with high-cost months, such as September. Because Energy Division's annual PRM or seasonal PRMs both start from the premise of equivalency between May and September PRMs, Energy Division's Draft PRM Study results in higher-cost PRMs than alternative PRMs that are just as reliable. From this analysis, we recommend specific PRMs for 2028 and 2029, plus additional changes to the Energy Division's PRM study process to generate risk-reserve curves in future PRM studies.

2. Study Methodology and Assumptions

This section describes CalCCA's systematic approach for: (1) generating monthly risk-reserve curves; and (2) using the curves to select PRMs according to different criteria while meeting a LOLE of 0.1 events/year. In general, the approach relies on tools, data, and assumptions provided by Energy Division to generate the risk-reserve curves consistent with projections of system conditions in 2028. However, because of the uncertainties in modeling the risk of loss-of-load events and calculation of achieved reserve margins, the approach defines several risk-reserve cases and corresponding curves for each case.

a. Generation of Risk-Reserve Curves

Generating risk-reserve curves starts by recognizing that any portfolio of resources, R_i, will have: (1) an achieved reserve margin, α_m, based on the accreditation rules; and (2) a risk of loss-of-load events under realistic power system operating conditions. There is some unknown relationship between achieved reserve margin and risk of loss-of-load events, $f^m(\alpha_m)$, that we can sample by calculating the risk and reserve for that particular portfolio, as shown in Figure 1.

Because the RA program requires monthly showings, we calculate the achieved reserve margin and risk for each month of the year, m. The risk with the portfolio can be measured by the expected number of days with loss-of-load events ($LOLE_m$), the expected number of hours with unmet demand ($LOLH_m$), or the expected unserved energy (EUE_m).

By systematically adding or removing resources from the portfolio, we can sample different points on the risk-reserve curve for each month. In this study, we start with the Baseline portfolio, R_B, then remove capacity in one of two ways. One way is to remove perfect capacity from the baseline portfolio, equivalent to Energy Division's concept of a negative operating unit (NOU). Removing perfect capacity from the Baseline lowers the portfolio's accredited capacity and achieved reserve margin. Removing perfect capacity also increases the risk of loss-of-load events. The second way to remove capacity from the Baseline portfolio is to proportionally decrease the nameplate capacity of all resources in the Baseline portfolio (except for hydropower and pumped hydro storage), following the convention used by Southern California Edison Company (SCE) in its Draft 2028 PRM Study.[7]

[7] SCE, *Draft 2028 Loss of Load Expectation Study Report* (August 14, 2026), at 9, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M614/K587/614587075.PDF.

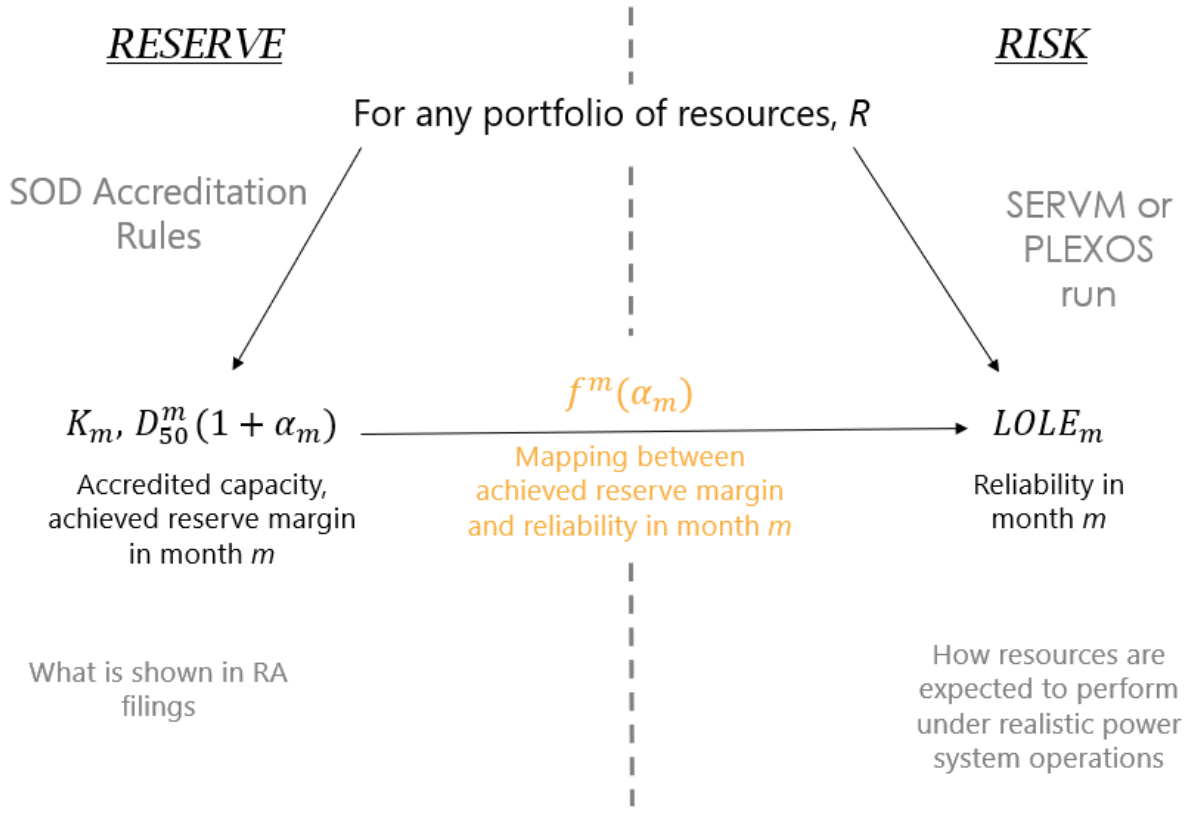


Figure 1. Illustration of the relationship between achieved reserve margin and risk of unmet demand for a particular portfolio of resources.

For each new portfolio, we calculate the corresponding achieved reserve margin and risk. We record the data for each of the risk-reserve cases in a risk-reserve database included with CalCCA's study results available on CalCCA's website.[8] We sampled portfolios that remove 500 megawatts (MW) to 25,000 MW of perfect capacity (in 500 MW increments) and portfolios that scale down the Baseline by 1 percent to 50 percent (in one percent increments).

We interpolate between the sampled portfolios to estimate the continuous risk-reserve curve, $\widehat{f^m}(\alpha_m)$, used in the optimization techniques and other numerical methods for determining PRMs.[9]

[8] CalCCA's final study results are available at: https://cal-cca.org/wp-content/uploads/2026/11/CalCCA_2028_PRM_Study_Final_2026-11-02.xlsx.

[9] Interpolation between datapoints in the risk-reserve curves used the "Piecewise Cubic Hermite Interpolating Polynomial" approach implemented in the Scipy.interpolate package in the PchipInterpolator class. *See* Scipy API, Scipy.interpolate.PchipInterpolator (2008), https://docs.scipy.org/doc/scipy/reference/generated/scipy.interpolate.PchipInterpolator.html. The advantage of this interpolation method over a traditional cubic-spline interpolator is that it preserves monotonicity in the interpolation data and enforces continuity in the slope between points. Monotonicity and continuous slopes make it easier to find the optimum when we use the risk-reserve curves to find cost-minimizing PRMs.

The following sections provide additional details and assumptions used to calculate the risk-reserve curves.

i. Achieved Reserve Margin

To calculate the achieved reserve margin of any portfolio, we calculate the accredited capacity of the portfolio under the SOD accreditation rules using the Energy Division's PRM Calibration Workbooks provided at the September 15, 2026, Draft PRM Study Workshop (Workshop).[10] In all cases, we use the version of the workbook that accredits conventional resources using the UCAP EFORd + Ambient convention that is consistent with the accreditation rules that the Commission will use in the 2028 RA program.[11]

For faster processing, we developed Python code that pulls in the Baseline portfolio from the PRM Calibration Workbook, then reduces the portfolio capacity by removing perfect capacity or proportionally reducing the Baseline. The Python code then dispatches the storage resources across each peak day to maximize the minimum achieved reserve margin within the SOD accreditation rules, consistent with the Excel Solver logic in the PRM Calibration Workbook. The achieved reserve margin in each hour is based on the ratio of the portfolio's accredited capacity, K_m, to the 1-in-2 peak demand, D_{50}^m. In particular, $\alpha_m = \frac{K_m}{D_m^{50}} - 1$.

As noted in CalCCA's Draft 2028 PRM Study,[12] our calculation of achieved reserve margin differs from Energy Division's. CalCCA removes perfect capacity from the portfolio (decreasing the numerator, K_m) and Energy Division instead adds flat load to the demand (increasing the denominator, D_{50}^m). The resulting difference in achieved reserve margins becomes larger the more capacity is removed from the Baseline or the more flat load is added to the forecasted peak demand. The difference is also larger when the forecasted peak demand, D_{50}^m, is smaller. As a result, the differences between reserve margins calculated with CalCCA's convention and Energy Division's convention are most acute in low demand months where significant amounts of perfect capacity can be removed before experiencing loss-of-load events, such as April.

We only report the achieved reserve margin in the tightest hour, where the tightest hour is the hour of the peak day with the lowest achieved reserve margin. When multiple hours have the same

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[10] September 15, 2026, Workshop: *Energy Division Updated PRM Results*, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/8-17-2026-track-2/prm-results-20260915-workshop.zip.

[11] D.26-07-008, *Decision Adopting Local Capacity Obligations for 2027-2029, Flexible Capacity Obligations for 2027, and Program Refinements*, R.25-10-003 (July 10, 2026), Ordering Paragraph 13, adopts the principles in Appendix B, Unforced Capacity Framework, which includes ambient thermal derates in the accreditation, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M610/K575/610575803.PDF.

[12] CalCCA Draft 2028 PRM Study, n. 29. The achieved reserve margin of a portfolio using CalCCA's convention will exceed the achieved reserve margin of the same portfolio when calculated using the Commission's convention by a factor of $\frac{NOU}{D_{50}^m + NOU}$.

minimum achieved reserve margin, as was commonly observed, we select the hour with the lowest amount of excess capacity from the non-storage resources.[13] Excess capacity is the amount that the accredited capacity of non-storage resources exceeds the hourly demand.

Our Python version of the PRM Calibration Workbook includes two other variable features. First, we can calculate reserves using the 1-in-2 peak demand directly from the 2025 Integrated Energy Policy Report (IEPR) forecast for the CAISO system in 2028 (2025 IEPR) or we can use the 1-in-2 peaks from the 25 weather years of managed load calculated by Energy Division (SERVM). Ideally, the 1-in-2 peak demand of the 25 weather years would match the 2025 IEPR forecast. However, the calibration approach used by the Energy Division matched the 2025 IEPR consumption rather than managed load.[14] Using the 2025 IEPR peak demand in the reserve calculations, while the power system operations are simulated under varying loads that have a different 1-in-2 peak, is inconsistent. Cases with reserves calculated using either the 2025 IEPR or SERVM peaks allow us to quantify the implications of this mismatch on PRMs.

Second, the Python code allows different choices for the accreditation of interchange capacity, representing the amount of imports shown in RA filings. The PRM Calibration Workbooks from the Energy Division assume 4,000 MW of interchange capacity in all hours in the months of June to September and 8,500 MW in all hours for the other months of the year. As described below, stakeholder perspectives differed regarding the amount of interchange capacity to use in calculating the achieved reserve margin of the Baseline portfolio and its variations.[15]

ii. Risk of Unmet Demand

To calculate the risk of loss-of-load events of any portfolio, we simulate the performance of the portfolio in a probabilistic reliability model built by CalCCA in the PLEXOS energy modeling software. Key assumptions and data sources for the final study are summarized in Appendix A.

The probabilistic reliability model uses a detailed hourly representation of resource availability, energy storage dispatch, load, operating reserve requirements, and import availability to quantify probability of unmet demand for each month. From the unmet demand, we calculate the three-risk metrics: $LOLE_m$, $LOLH_m$, and EUE_m. In addition, CalCCA included a limited number of production cost-related parameters to generate a reasonable representation of energy market prices. In

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[13] Our decision to choose the hour with the lowest excess capacity differs from our assumption in the Draft Study, where we chose the first hour with the minimum achieved reserve margin. We adjusted our assumptions simply to better align with the Energy Division's approach where possible.

[14] *Administrative Law Judge's Ruling on Energy Division's Proposed Inputs and Assumptions*, R.25-10-003 (April 10, 2026), Attachment 2 (Energy Division's I&As), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M604/K617/604617992.PDF.

[15] CalCCA described draft study differences during the Workshop, at Slide 80, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/8-17-2026-track-2/r2510003-workshop-on-lole-studies20260915version-2.pdf.

addition to the three reliability metrics, we now also report the unhedged expected energy market cost to load, defined as the probability-weighted average product of the hourly energy market price and hourly CAISO managed load.

CalCCA mostly aligns the data and assumptions of the PLEXOS model with Energy Division's SERVM model. We chose to deviate from the Energy Division's SERVM model primarily to make the model easier to manage and to make the model run faster. For production cost-related parameters, we also deviate due to the confidential nature of some data used by the Energy Division. Important differences from the Energy Division's SERVM model include:

- Equivalent units rather than unique units: To make the model easier to manage, CalCCA's PLEXOS model represents all of the combined cycle capacity in CAISO, for example, as 44 units with the same capacity, heat rate, forced outage rate, and thermal derates. These units experience unique forced outages and are dispatched individually, but their characteristics are equivalent. Energy Division's SERVM model, on the other hand, includes unit-specific parameters for the same 44 units in the Baseline.
- No intra-CAISO transmission constraints: To make the model easier to manage and run faster, CalCCA's PLEXOS model groups CAISO loads and resources into a single region with no internal transmission limitations. Treating CAISO as a single region also means that we do not need to make decisions about how to spatially allocate Baseline capacity reductions within the CAISO region. Energy Division's SERVM model includes three regions within CAISO, with transmission between PG&E and SCE regions constrained by the Path 26 limit.
- Neighboring region representation: To make the model easier to manage and run faster, CalCCA's PLEXOS model includes simplified representation of availability of resources from neighboring regions and groups non-CA neighbors into a southwest (SW) and northwest (NW) region. Additional details are included in Appendix B. Energy Division's SERVM model includes additional transmission and region granularity for neighboring regions along with dispatching individual units to minimize overall system costs subject to limits.
- Limited representation of dispatch costs: CalCCA originally built the PLEXOS model only to estimate reliability metrics, which are independent of production cost parameters. To estimate expected energy market costs, CalCCA added rough estimates of technology-type heat rates, annual-average fuel costs, fuel-type specific CO2 emission rates, and annual average CO2 emission prices. In addition, CalCCA assumes energy market operators would pay up to $2,000/ megawatt hours (MWh) to avoid shedding load. Energy Division's SERVM model includes significantly more detail on confidential unit-specific heat rates and unit-specific flexibility parameters, both of which can impact emission rates. It also includes location and month-specific fuel prices and transmission line-specific hurdle rates, which CalCCA excludes to make the model easier to manage.

iii. Risk-Reserve Cases

During the Workshop, it became clear that several key modeling assumptions remain uncertain. Rather than presenting a single set of monthly risk-reserve curves, as presented in CalCCA's Draft 2028 PRM Study, CalCCA's Final 2028 PRM Study presents different sets of assumptions impacting risk and reserves that lead to different sets of curves. In this study, CalCCA developed twelve different risk-reserve cases, summarized in Table 1, to address three areas:

- The source of the peak demand for reserve calculations;
- The portion of the Baseline that remains uncontracted and therefore unable to contribute to CAISO reliability; and
- Treatment of economic imports (non-RA imports) in probabilistic reliability modeling and reserve calculations.

Table 1. Risk-Reserve cases used in this study to evaluate the impact of uncertainties on PRMs.

Case	Capacity Adjustment Type	Risk	Reserve		
		Simultaneous Import Limit	Interchange Accreditation	Managed Load 1-in-2	Conventional Accreditation
A	NOU	CPUC Limit	4GW	SERVM	UCAP EFORd + Ambient
B	NOU	CPUC Limit	ED Sep Workshop	SERVM	UCAP EFORd + Ambient
C	NOU	CPUC Limit	SCE Draft	SERVM	UCAP EFORd + Ambient
D	NOU	CPUC Limit	CPUC SIL	SERVM	UCAP EFORd + Ambient
E	NOU	4GW	4GW	SERVM	UCAP EFORd + Ambient
F	NOU	CPUC Limit	ED Sep Workshop	2025 IEPR	UCAP EFORd + Ambient
A'	Scaled	CPUC Limit	4GW	SERVM	UCAP EFORd + Ambient
B'	Scaled	CPUC Limit	ED Sep Workshop	SERVM	UCAP EFORd + Ambient
C'	Scaled	CPUC Limit	SCE Draft	SERVM	UCAP EFORd + Ambient
D'	Scaled	CPUC Limit	CPUC SIL	SERVM	UCAP EFORd + Ambient
E'	Scaled	4GW	4GW	SERVM	UCAP EFORd + Ambient
F'	Scaled	CPUC Limit	ED Sep Workshop	2025 IEPR	UCAP EFORd + Ambient

Cases A through E use progressively more conservative assumptions regarding the treatment of energy-only economic imports, those imports that occur above and beyond the import capacity shown by LSEs in RA filings.

Case A assumes only 4 gigawatts (GW) of interchange capacity in the Baseline portfolio. The probabilistic reliability model in Case A allows any available resources to be imported into CAISO up to the simultaneous import limit (SIL) defined by Energy Division.

Conversely, Case D and E conservatively require any import in the probabilistic reliability model to have been shown in an RA filing, and therefore included in the accredited capacity of the Baseline portfolio.

In the middle, Case B treats imports consistent with the Energy Division's Draft 2028 PRM Study, where the accredited interchange capacity used in reserve calculations is 4 GW in all hours of June-September and 8.5 GW other months, while the SIL in the probabilistic reliability model is sometimes higher. Case C accredits interchange capacity in line with SCE's assumptions in its Draft 2028 PRM Study.

The different interchange accreditation and import limit assumptions for each Case A-E are summarized in Figure 2.

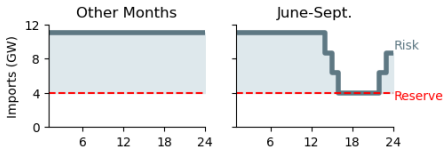
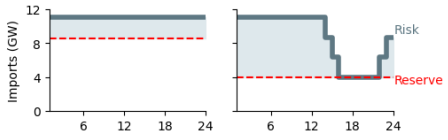
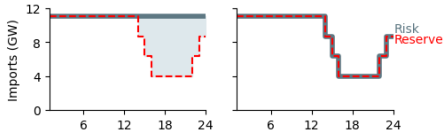
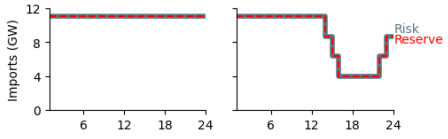
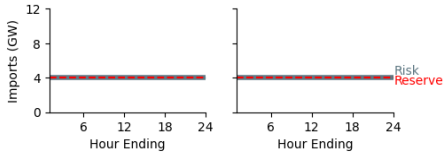
	Risk	Reserve	
Case	Simultaneous Import Limit	Interchange Accreditation	
A	CPUC Limit	4GW	
B	CPUC Limit	ED Sep Workshop	
C	CPUC Limit	SCE Draft	
D	CPUC Limit	CPUC SIL	
E	4GW	4GW	

Figure 2. Differences in assumptions regarding interchange accreditation in reserve calculations and import limits in probabilistic reliability modeling. The light blue shaded area between interchange accreditation and import limits represents the potential for economic imports.

Historical relationships between the capacity of imports shown in RA filings and the observed hourly imports during actual system operations, shown in Figure 3, suggest that Case A is not only reasonable, but it in fact also reflects likely outcomes. In contrast, Case D and E, which assume imports in the probabilistic modeling can never exceed the imports shown in RA filings, are overly conservative relative to recent observations.

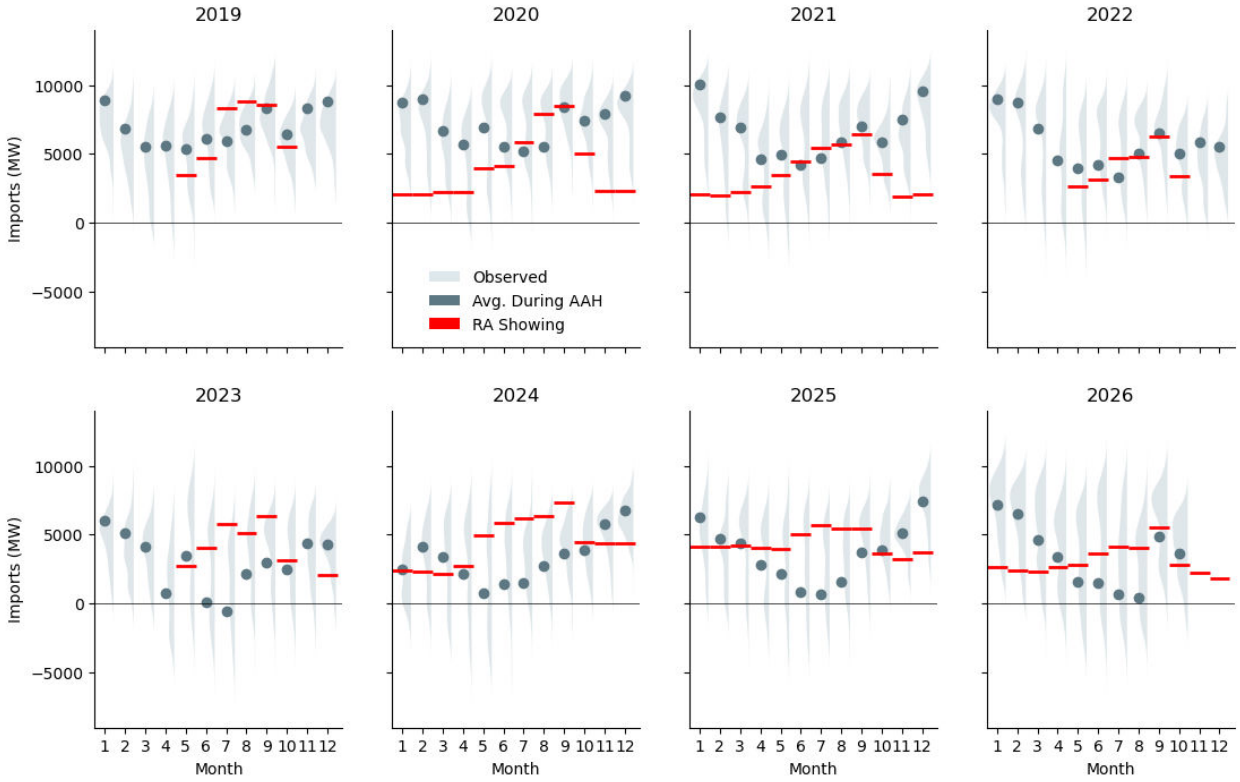


Figure 3. Historically observed imports to the CAISO system often exceed the capacity of import RA shown in LSE filings. [16]

Case F is a sensitivity to Case B to test the importance of the source of peak load data in reserve calculations. In Case F, the peak load used in reserve calculations comes from the 2025 IEPR. In Case B, the 1-in-2 peak managed load is instead derived from the 25-year weather data used in the probabilistic reliability modeling.

Cases A' through F' test the sensitivity of risk-reserve curves to reductions in Baseline capacity by using proportional scaling (Scaled) instead of removing perfect capacity (NOU).

[16] Historical RA import data are primarily obtained from the CAISO Historical Resource Adequacy Aggregate Data Report, https://www.caiso.com/documents/historicalresourceadequacyaggregatedata.xlsx. RA imports from months not covered by this report were obtained from earlier RA import report, https://www.caiso.com/Documents/CaliforniaISOPublishedHistoricalResourceAdequacyImportAggregateData.html (no longer available) or downloaded from the Available Import Capability report at oasis.caiso.com. Observed hourly reports are from the EIA Hourly Electric Grid Monitor report of CISO hourly interchange.

Cases B and F are the closest match to the risk-reserve modeling assumptions used by the Energy Division in the Workshop.

b. PRM Selection Criteria

Risk-reserve curves on their own do not provide sufficient information to recommend PRMs. Additional selection criteria are needed in order to get specific PRMs. Criteria considered in this study are summarized in Table 2. Previous analysis by the Energy Division suggests two criteria: (1) equivalent PRMs across all months (Annual) and (2) equivalent PRMs across the months of May-September with all loss-of-load events concentrated in those months and a separate PRM in all other months (Seasonal2). CalCCA's I&As propose to select monthly PRMs in a way that minimizes RA costs while meeting a LOLE of 0.1 events/year. RA costs can be thought of as varying with each month's required RA capacity (MonthlyRACost) or as varying with the highest RA requirement across any of the months (AnnualRACost).

Table 2. PRM selection criteria used in this study all meet a LOLE of 0.1 events/year.

PRM Selection Criteria	Description
Annual	Set single annual PRM at LOLE=0.1
Seasonal2	Set summer PRM where LOLE_summer=(0.1-0.00001) and nonsummer PRM where LOLE_nonsummer = 0.00001. Summer months are May-September.
Seasonal3	Set summer PRM where LOLE_summer =(0.1-0.00001). Set shoulder and spring PRM each at LOLE_season = 0.000005. Summer months are June-September, Spring months are April and May.
CAISOTargetLOLE	Set monthly PRMs to match CAISO Target LOLE distribution.
MonthlyRACost	Set monthly PRMs to minimize RA costs, where RA costs vary by monthly RA requirement, subject to LOLE<=0.1.
AnnualRACost	Set monthly PRMs to minimize RA costs, where RA costs vary by highest annual RA requirement, subject to LOLE<=0.1.
MonthlyTotalCost	Set monthly RA costs to minimize sum of RA costs, expected unhedged energy market costs, and unserved energy costs at the VOLL, subject to LOLE<=0.1. Energy market costs are product of hourly managed load and hourly energy market price.

Two additional PRM selection criteria that meet a LOLE of 0.1 events/year emerged during research and discussions with stakeholders. *First*, the CAISO sets default monthly PRMs for LSEs whose Local Regulatory Authority (LRA) does not set a PRM. In the CAISO's most recent default PRM study, the CAISO selected monthly PRMs that meet the 0.1 LOLE reliability metric with a specific distribution of loss-of-load events between months.[17] The Commission could set its own monthly PRMs, while using the same monthly distribution of loss-of-load events as the CAISO.

Second, stakeholder questions on CalCCA's proposal to select PRMs that minimize RA costs raised the concern that RA costs are only a subset of the wholesale generating costs faced by customers. These stakeholders stated that energy market costs and the economic cost of any unmet demand can also impact customer costs. If PRMs are set to only minimize RA costs, overall consumer costs could increase if the RA cost minimizing PRMs result in increased energy market costs or economic costs of unmet demand. Another possible PRM section criterion is therefore to minimize total consumer costs, including RA market costs, energy market costs, and economic costs from unmet demand, while meeting a LOLE of 0.1 events/year (MonthlyTotalCost).

For reasons further explored in the Analysis section below, we believe that this last criterion is misguided as it implies that the only way to reduce customer exposure to high energy market prices is through RA contracts. This is not the case: today, an LSE can purchase non-RA fixed price energy market products for delivery in 2028 that insulate the consumer from spot prices in 2028. In fact, most if not all LSEs have some form of risk-management policy that guides LSE hedging decisions to limit exposure to spot market prices. The relevant energy market cost that varies with PRMs is therefore only the unhedged portion, which varies from LSE to LSE in line with their risk-management strategy. Further, the assumption that increased amounts of RA will mitigate energy market prices is predicated on the notion that without the must offer obligation, the resource would have bid a higher price to the energy market or not bid into the energy market at all. This assumption is highly dependent on market competitiveness at any given point in time, the CAISO's rules for market power mitigation, as well as the other contractual circumstances between the resources and LSEs (e.g., energy only resources that do not provide RA but do provide energy at a contractual price). All of these items make it questionable whether changes in RA requirements impact energy prices. We include this criterion only to illustrate the sensitivity of the resulting PRMs to assumptions about the unhedged portion, not as a valid PRM selection criteria.

[17] CAISO Business Practice Manual for Reliability Requirements 13.3.2 "CAISO calibrates the model to an annual loss of load expectation of 0.1, then evaluates the number of unserved energy events occurring in each calendar month and adjusts the individual month LOLE targets, if appropriate. When adjusting the monthly LOLE targets, CAISO considers factors relating to system reliability, including, but not limited to forecasted peaks, load uncertainty, changing load patterns, and impacts on PRMs and QC results. After setting a monthly LOLE target, each calendar month is individually calibrated to that target."

i. Annual PRM Criteria

The Annual PRM selection criteria require the PRM to be equal across all months and that LOLE equal 0.1 events/year. Using monthly risk-reserve curves, the resulting PRM can be found graphically by stacking the curves vertically, which represents the sum of the monthly LOLE for the equivalent achieved reserve margin across all months, and finding the achieved reserve margin where the sum of monthly LOLE equals 0.1. This approach is illustrated in Figure 4.

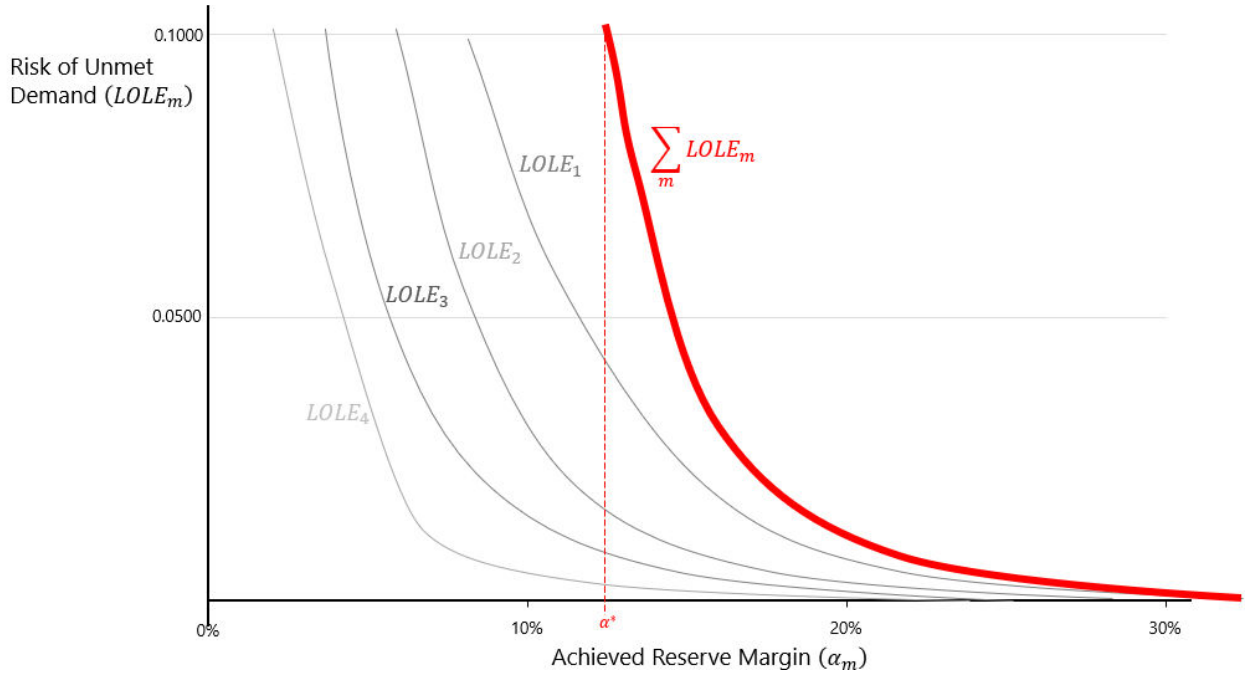


Figure 4. Illustration of the process for using monthly risk-reserve curves to find a single annual PRM that meets a LOLE of 0.1 events/year.

ii. Seasonal2 PRM Criteria

The Seasonal2 PRM selection criteria builds on the same approach as the Annual criteria but separates the risk-reserve curves into two seasons. In the summer season, defined by Energy Division as May-September, a single summer PRM is chosen such that nearly all of the loss-of-load events are in the summer. A summer risk-reserve curve can be found by stacking the summer month risk-reserve curves vertically then finding the achieved reserve margin where the sum of the LOLE in the summer months is just below 0.1. The non-summer risk-reserve curve is made by stacking the non-summer month risk-reserve curves and finding the achieved reserve margin where the sum of the LOLE in the non-summer months just begins to exceed zero. This approach is illustrated in Figure 5.

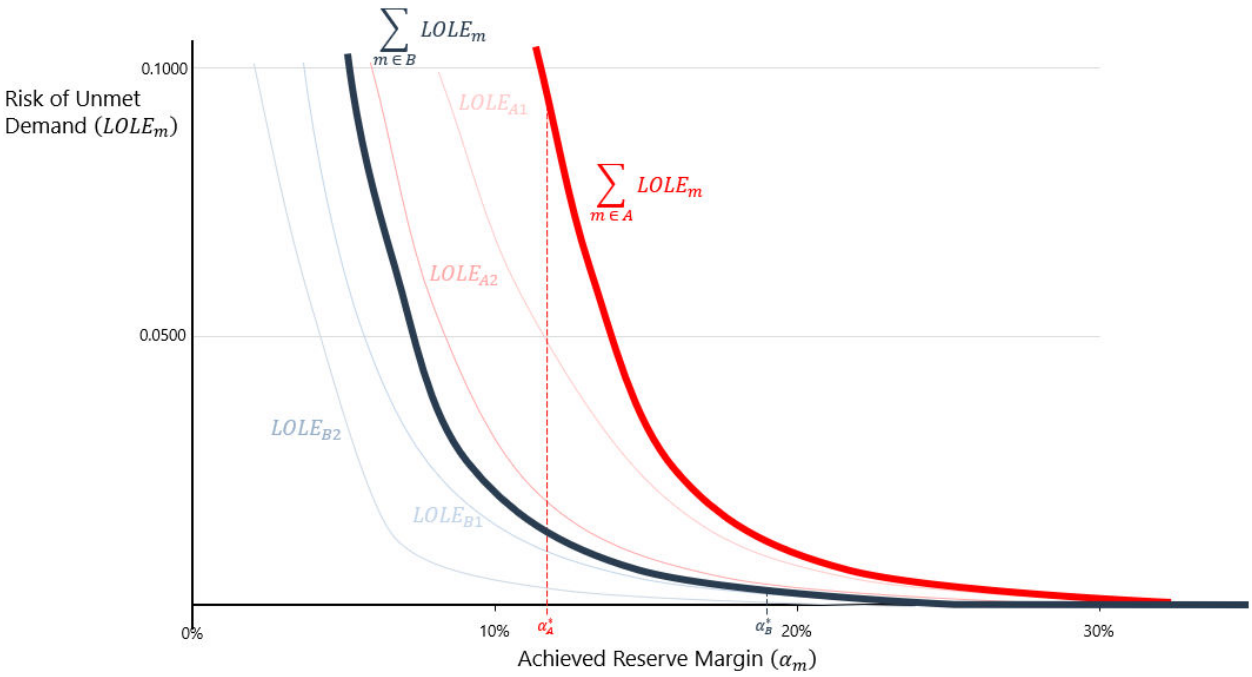


Figure 5. Illustration of the process for using monthly risk-reserve curves to find a seasonal PRM where nearly all of the loss-of-load events are allocated to the summer season (Season A) and very few are allocated to non-summer (Season B), while meeting a LOLE of 0.1 events/year.

iii. Seasonal3 PRM Criteria

The Seasonal3 PRM selection criteria extends the two-season approach from Energy Division to include three seasons. The summer season, with nearly all the loss-of-load events, is narrowed to June-September. The remaining months are divided into a highly-variable spring (April and May) and less variable shoulder season (remaining months). The PRM for the spring and shoulder season is set such that the LOLE just begins to exceed zero in each season.

The purpose of this additional season is to ensure that the high degree of load variability observed around the median 1-in-2 peak load in the spring does not result in higher-than-necessary PRMs in the summer months, where RA costs are typically the highest.

iv. CAISOTargetLOLE PRM Criteria

The CAISOTargetLOLE PRM selection criteria use the risk-reserve curves to find the monthly achieved reserve margin where the resulting LOLE in the month matches the LOLE for the corresponding month in the CAISO target distribution.[18] For example, the CAISO Target LOLE for September allows 24 loss-of-load event days out of 500 equally-weighted samples, equivalent to a September LOLE of 0.048 (24/500). Similar to September, the CAISO Target LOLE distribution

[18] CAISO 2027 Default Resource Adequacy Values: Draft PRM and QC values (September 9, 2026), at Slide 32. https://stakeholdercenter.caiso.com/InitiativeDocuments/Presentation-2027-Default-Resource-Adequacy-Values-Sep-9-2026.pdf. To set the default PRM such that it achieves a 0.1 LOLE, CAISO targets 6 events in June, 8 events in July, 8 events in August, 24 in September, and 4 in October. In total 50 loss-of-load events out of 500 samples leads to a LOLE of 0.1 events/year.

defines a specific number of loss-of-load events in each month. The target LOLE in each month can be used to find the achieved reserve margin on the corresponding monthly risk-reserve curve, establishing the month's PRM under the CAISOTargetLOLE criteria. This approach is illustrated in Figure 6.

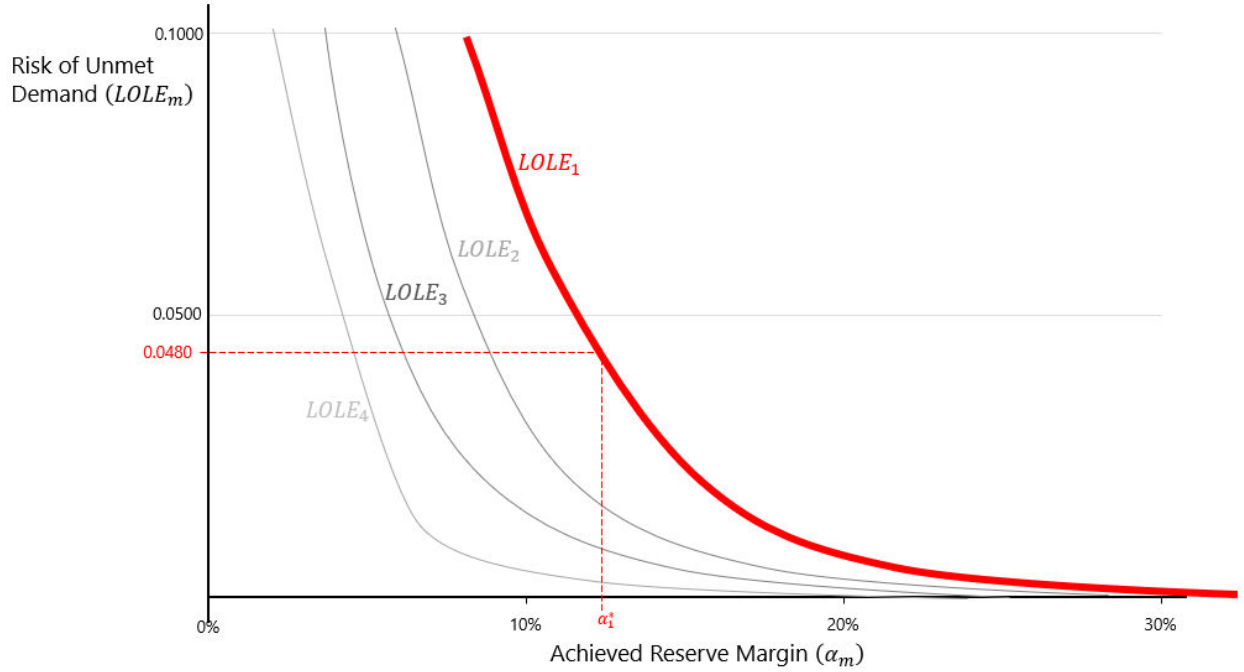


Figure 6. Illustration of the process for using monthly risk-reserve curves to find a monthly PRM where the distribution of loss-of-load events matches the target number of events defined by the CAISO target LOLE. In this case, the CAISO target LOLE for month 1 is 0.048, or 24 out of 500 equally-weighted samples.

v. MonthlyRACost PRM Criteria

The MonthlyRACost PRM selection criteria uses the risk-reserve curves in a constrained optimization that minimizes RA costs subject to the requirement that the total LOLE be less than or equal to 0.1 events/year.[19] RA costs are assumed to vary in proportion to each month's product of the RA requirement and a monthly RA price. The optimization problem chooses α_m^* [PRM in each month] to:

[19] The solver is trying to lower the PRM in all months to reduce RA costs, but as it does so it faces increases in LOLE. At the optimum, the first-order necessary conditions require equal ratios of marginal decreases in monthly RA costs to marginal increases in the monthly LOLE with decreasing achieved reserve margin across all months. Marginal RA costs in any month are the product of peak demand and the RA price ($D_{50}^m p_K^m$), while marginal LOLE is the slope of the risk-reserve curve ($\frac{d\widehat{f^m}}{d\alpha_m}$). At the optimum, months where a reduction in PRM leads to only modest RA cost savings (because of a low peak demand or low RA price) will have a PRM in the shallow part of a risk-reserve curve where changes in LOLE are also modest. Conversely, months where a reduction in PRM can produce large RA cost savings (because of high peak demand or high RA prices), will have PRMs in the steeper part of a risk-reserve curve where using more of the available LOLE budget from lowering the PRM is worth the RA cost savings.

$$minimize\ \sum_m D_{50}^m(1+\alpha_m)\cdot p_K^m \qquad \text{[Least Cost]}$$

$$such\ that\text{:}\ \sum_m \widehat{f^m}(\alpha_m) \le 0.1 \qquad \text{[Reliable]}$$

Where:

- D_{50}^m – Peak 1-in-2 managed demand in month m
- α_m– Achieved reserve margin in month m
- p_K^m – Price of accredited capacity in month m
- $\widehat{f^m}(\alpha_m)$ – Estimated risk-reserve curve relating achieved reserve margin in month m to LOLE in m

Actual RA costs in 2028 will depend on 2028 RA prices, which are not yet known. CalCCA recommends that the most-recent publicly available RA prices be used to calculate PRMs using this criteria. Three public RA prices options were available for CalCCA's Final 2028 PRM Study. The prices are summarized in Table 3.

- 2023 RA Market Report: monthly weighted-average prices for all RA transactions for delivery in 2023 reported in the Energy Division's most recent 2023 RA Market Report;[20]
- 2025 FERC EQR: monthly weighted-average prices for capacity product transactions sold to California LSEs for delivery in 2025 reported in FERC Electric Quarterly Reports, as cleaned and organized by CalCCA;[21]
- 2027 MPB forecast: annual weighted average of RA transactions for delivery in 2027 as reported in the Energy Division's PCIA forecast of the 2027 market price benchmark (MPB). We assume the annual average price is equal across all months.[22]

[20] Energy Division, *2023 Resource Adequacy Report* (Aug. 2025), at 27-28, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2023-ra-reportv3.pdf.

[21] Capacity transactions are from FERC electronic quarterly reports (EQR) downloaded from https://eqrreportviewer.ferc.gov/ and cleaned by CalCCA.

[22] *Market Price Benchmark Calculations 2026* (Oct. 1, 2026) https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/community-choice-aggregation-and-direct-access/2026-market-price-benchmarks.pdf.

Table 3. RA market prices used to calculate monthly RA costs and find PRMs that minimize monthly RA costs.

Month	RA Price ($/kW-mo)		
	2023 RA Market Report	2025 FERC EQR	2027 MPB Forecast
1	5.66	10.19	10.02
2	5.66	9.93	10.02
3	5.36	9.78	10.02
4	5.84	10.23	10.02
5	7.13	11.66	10.02
6	10.80	12.81	10.02
7	17.50	14.60	10.02
8	21.43	15.47	10.02
9	24.07	16.40	10.02
10	11.37	11.63	10.02
11	6.51	10.55	10.02
12	7.01	9.79	10.02

vi. AnnualRACost PRM Criteria

In some cases, LSEs procure RA contracts in annual strips, rather than monthly quantities. In this circumstance, RA costs depend on the highest RA requirement across the entire year. RA contracts that can meet the highest month are therefore available to meet RA requirements in any other month too. This changes the objective function in the RA cost minimization problem, but uses the same risk-reserve curves and constraint requiring that the total LOLE be less than or equal to 0.1. Changing the RA cost definition changes the problem to choosing α_m^* [PRM in each month] to:

$$minimize \ \max_m\{D_{50}^m(1+\alpha_m)\} \cdot p_K \qquad \text{[Least Cost]}$$

$$such\ that\text{:}\ \textstyle\sum_m \widehat{f^m}(\alpha_m) \leq 0.1 \qquad \text{[Reliable]}$$

Where:

- p_K – Annual price of accredited capacity

vii. MonthlyTotalCost PRM Criteria

The MonthlyTotalCost PRM selection criteria expands the costs considered in the objective function to include unhedged expected energy market costs and expected unserved energy costs, in addition to the monthly RA costs. The monthly unhedged expected energy market costs and unserved energy depend on the portfolio of resources available to the CAISO market. These change with the achieved reserve margin, similar to the way that monthly LOLE changes with the achieved reserve margin. The expected unserved energy costs are the product of the expected unserved energy and an assumed value of lost load (VOLL).

The VOLL is difficult to observe,[23] and therefore highly uncertain. A recent U.S. estimate of customer interruption costs estimated a VOLL of $5,030/MWh for residential customers associated with a 2-hour duration event and $100,000/MWh for non-residential customers.[24] With roughly 66 percent of CPUC-jurisdictional retail sales being non-residential,[25] we use a sales-weighted average VOLL of $67,710/MWh.

The PRMs that meet this selection criteria can again be expressed as a constrained optimization that minimizes total costs while meeting a LOLE of 0.1 events/year. With this optimization, we choose α_m^* [PRM in each month] to:

$$minimize\ \sum_m D_{50}^m(1+\alpha_m)\cdot p_K^m + U\cdot \widehat{g^m}(\alpha_m) + VOLL\cdot \widehat{h^m}(\alpha_m) \qquad \text{[Least Cost]}$$

$$such\ that\text{:}\ \sum_m \widehat{f^m}(\alpha_m) \le 0.1 \qquad \text{[Reliable]}$$

Where:

- U – Portion of energy market costs that are unhedged
- $\widehat{g^m}(\alpha_m)$ – Estimated curve relating achieved reserve margin in month m to unhedged expected energy market costs in m
- $VOLL$ – Value of lost load
- $\widehat{h^m}(\alpha_m)$ – Estimated curve relating achieved reserve margin in month m to EUE in m

The fraction of energy market costs that are unhedged, U, is a risk-management decision directly in the control of each individual LSE. The results in CalCCA'sPRM_problem_solution_database show the worst case, in which LSEs are 100 percent unhedged for 2028 energy market purchases (MonthlyTotalCostUnhedged) or a best case where LSEs are 100 percent hedged (MonthlyTotalCostHedged). The hedging fraction can be directly chosen by each individual LSE independent of the achieved reserve margin. The MonthlyTotalCost PRM selection criteria should therefore not be used to set PRMs, and is only included in the analysis for completeness.

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[23] Will Gorman, "The quest to quantify the value of lost load: A critical review of the economics of power outages", *The Electricity Journal*, Volume 35, Issue 8, 2022, 107187, https://doi.org/10.1016/j.tej.2022.107187.

[24] Larsen, P.; Carney, K.; Eto, J.; Jiang, G.; Joshi, D.; LaCommare, K., et al. (2026). *ICE Calculator 2: Final Report for Phase 1 and 2 of the National Initiative to Update the Interruption Cost Estimate (ICE) Calculator.* Lawrence Berkeley National Laboratory. OSTI ID: 3021993. Retrieved from https://escholarship.org/uc/item/3s61v105.

[25] EIA-861 retail sales to bundled and unbundled customers for PG&E, SCE, and SDG&E in 2024, from https://www.eia.gov/electricity/data/eia861/.

3. Results

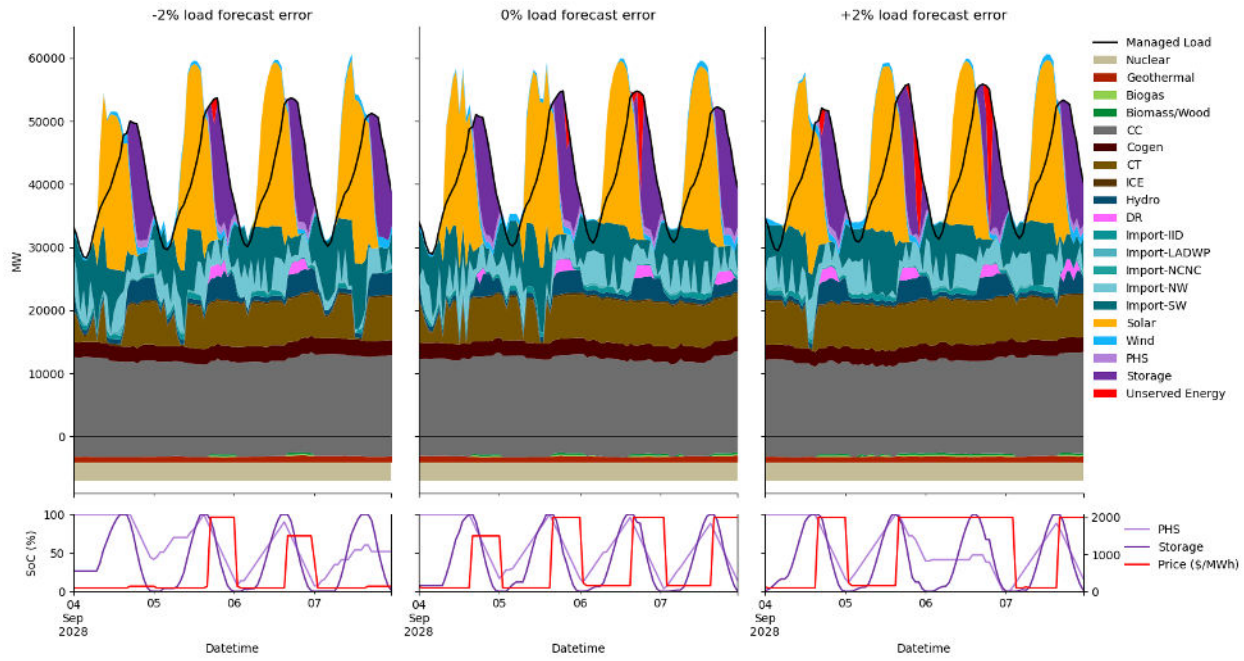
To reflect the wide range of modeling uncertainties and alternative PRM selection criteria, we calculated risk-reserve curves for twelve risk-reserve cases and used the resulting risk-reserve curves to calculate PRMs under eight different selection criteria. For each set of PRMs, we calculated the resulting RA costs using three sources of RA prices, each under two different assumptions of how RA costs vary (i.e., with monthly RA requirements or based on the highest annual requirement). The full set of results are available to stakeholders through an Excel file posted to CalCCA's website.[26]

The Baseline portfolio never experiences loss-of-load events under all risk-reserve cases. Not all the Baseline resources need to be committed to the CAISO market in all months to meet a LOLE of 0.1 events/year. Some portion of the Baseline can therefore go offline for maintenance or be committed to other markets without compromising reliability.

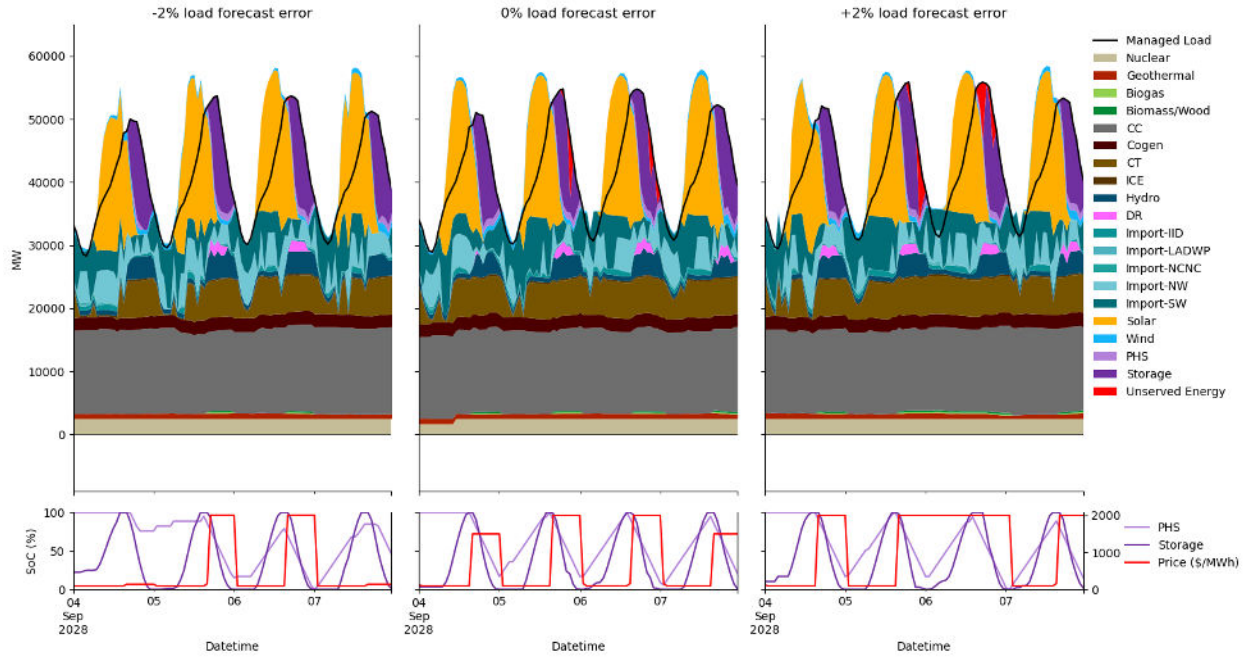
In all risk-reserve cases that set the SIL consistent with Energy Division's definition in the probabilistic reliability modeling (i.e., all cases except E and E'), roughly 6,500-7,000 MW of perfect capacity could be removed or 14 percent of each of the Baseline resources could be removed, before observing roughly a LOLE of 0.1 events/year. Cases with the SIL restricted to 4 GW in all hours and months, Cases E and E', start with less resources in the Baseline and therefore reach a LOLE of 0.1 events/year after removing 3,500 MW of perfect capacity or 8 percent of each of the Baseline resources, respectively.

In all cases, the loss-of-load events happen first in September, primarily under the load and resource characteristics consistent with the 2022 weather year. To illustrate the realistic power system operations reflected in the probabilistic reliability model, we show a dispatch report from PLEXOS for a series of stressful September days under the 2022 weather year, Figure 7. In one configuration, we remove 7,000 MW of perfect capacity from the Baseline. Mechanically, this removal of perfect capacity is achieved by creating a market object in the PLEXOS model that purchases 7,000 MW in all months and hours with higher priority than serving CAISO demand. The model allows imports up to the SIL defined by the Energy Division. In the other configuration, we scale the accessible nameplate capacity of the Baseline resources down by 14 percent, including a proportional reduction in the SIL.

[26] CalCCA's final study results in Excel: https://cal-cca.org/wp-content/uploads/2026/11/CalCCA_2028_PRM_Study_Final_2026-11-02.xlsx.



(a)



(b)

Figure 7. Example dispatch report from the probabilistic reliability model created in PLEXOS showing dispatch results on stressful days in September from the 2022 weather year with resources removed from the Baseline portfolio equivalent to (a) 7,000 MW of perfect capacity and (b) 14 percent of all non-Hydro and non-pumped hydro storage resources.

Both configurations see unserved energy in the evening after sunset and before the end of the period with restricted imports. Energy market prices rise to the assumed maximum CAISO bid cap of $2,000/MWh during times with unserved energy and other surrounding hours where battery dispatch is limited by the amount of stored energy. Unserved energy and energy market prices increase with load forecast error under the same stressful weather conditions. Eventually, with the highest load forecast error, energy prices rise to the bid cap throughout the night when resources are insufficient to fully charge energy storage between consecutive days with unserved energy. In essence, the high energy market prices in the early morning of September 6 indicate that a reduction in managed load, even when managed load is already at its lowest, could free up generating capacity to charge storage and avoid some unserved energy in the evening hours later in the same day.[27]

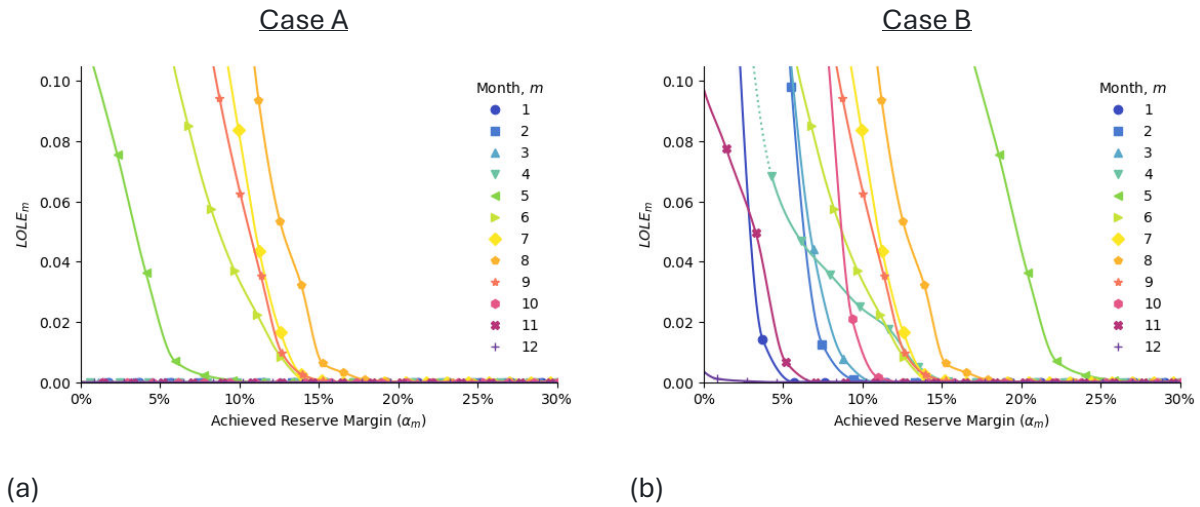


Figure 8. Risk-reserve curves change with modeling assumptions, particularly around accreditation of imports in non-summer months, as illustrated by comparing curves for Case A, assuming 4 GW of accredited imports in all hours and months, and Case B, which increases accreditation of non-summer months to 8.5 GW in all hours.[28]

Identifying a set of PRMs that meet reliability requirements requires calculation of a portfolio's achieved reserve margin to go along with the loss-of-load events found in the probabilistic reliability modeling of the portfolio. The results indicate that decisions about how to accredit

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[27] Random spikes in output occur when multiple resources could meet constraints with the same costs, resulting in the model seeing no advantage to dispatching one resource over another. Under these conditions the solution can bounce between equivalent options without otherwise affecting the objective of minimizing production costs. Similarly, nothing in the model indicates a preference for concentrating all loss-of-load in individual hours or spreading the event across multiple hours when it otherwise does not change the total amount of unmet energy. As a result, the spikes in unmet energy could presumably be mitigated if customers or system operators have a preference for longer-duration but less severe events over shorter-duration events with more customers affected.

[28] The dashed line in April represents an extrapolation of the risk-reserve curve, as opposed to the interpolation represented by the solid lines. Ideally, the systematical removal of capacity from the Baseline will include points on the risk-reserve curves that include up to 0.1 events/year. However, even removing 25 GW of perfect capacity or scaling the Baseline by 50 were insufficient to get to 0.1 events/year in April.

imports in the Baseline portfolio have significant implications for achieved reserve margins, particularly in the non-summer months. As a result, these decisions can dramatically shift risk-reserve curves, even while maintaining the same SIL assumptions in the probabilistic reliability modeling. To illustrate this point, we show the risk-reserve curves for Case A and B in Figure 8. Case A uses assumptions proposed by CalCCA to accredit imports with 4 GW of interchange capacity in all hours and months in the reserve calculations. Case B used Energy Division's proposal from the Workshop to accredit imports with 8.5 GW of interchange capacity in all hours of non-summer months and 4 GW in all hours of summer months.

To assess the implications of modeling assumptions on the risk-reserve curves, and therefore on PRMs, we start by analyzing results with a single PRM section criteria. Of all of the options, the CAISOTargetLOLE is unique in that the PRMs resulting from these criteria all have the same monthly distribution of LOLE, no matter the unique character of the risk-reserve curves. A change in a particular month's PRM, found using the CAISOTargetLOLE criteria, directly reflects a change to that same month's risk-reserve curve without any confounding interaction from changes in other month's curves. The same cannot be said for any of the other PRM selection criteria analyzed in this report. Such a characteristic does not make the CAISOTargetLOLE selection criteria more or less attractive from a policy perspective, but it does make it more useful from an analytical perspective when evaluating implications of uncertain assumptions. We first present the PRMs resulting from the CAISOTargetLOLE (PRM_{ISO}) in each of the twelve risk-reserve cases, Table 4. The monthly PRMs translate into monthly RA requirements, shown in Table 5. In the next section, we use these PRM_{ISO} results to analyze three primary sources of modeling uncertainty: the source of peak demand in reserve calculations, approach to removing capacity from the Baseline portfolio, and treatment of economic imports in reserve accreditation.

Finally, we use the full set of results to compare PRM selection criteria. All criteria meet a LOLE of 0.1 events/year, but they differ in terms of administrative complexity, distribution of LOLE across months, RA compliance costs, and relative performance on other reliability metrics. The comprehensive set of results inform CalCCA's PRM recommendations and can potentially help stakeholders understand reasons for differences across PRM studies.

Table 4. PRMs resulting from the CAISOTargetLOLE selection criteria (PRM_{ISO}) applied to each of the twelve risk-reserve cases.

Month	A	B	C	D	E	F	A'	B'	C'	D'	E'	F'
1	0.0%	6.7%	7.6%	16.6%	16.9%	6.2%	0.0%	8.9%	5.6%	14.1%	15.5%	9.0%
2	0.0%	11.2%	9.2%	21.0%	20.9%	10.8%	1.2%	10.2%	7.5%	15.3%	15.9%	10.4%
3	0.0%	13.0%	10.5%	22.8%	23.3%	12.7%	5.6%	14.7%	10.8%	19.7%	20.7%	15.0%
4	0.3%	16.9%	13.5%	26.3%	26.3%	17.1%	14.4%	23.6%	17.6%	28.8%	27.8%	24.9%
5	11.2%	27.4%	23.8%	36.6%	36.4%	28.1%	21.7%	31.4%	25.2%	36.7%	35.8%	32.9%
6	12.2%	12.2%	17.0%	17.0%	23.1%	14.3%	10.0%	10.0%	12.2%	12.2%	18.1%	12.7%
7	12.6%	12.6%	18.2%	18.2%	17.1%	15.2%	14.0%	14.0%	16.9%	16.9%	16.2%	16.7%
8	14.6%	14.6%	19.3%	19.3%	21.1%	17.2%	15.7%	15.7%	18.5%	18.5%	19.6%	18.7%
9	10.7%	10.7%	14.7%	14.7%	17.6%	13.2%	11.7%	11.7%	14.6%	14.6%	17.0%	14.3%
10	0.0%	10.1%	4.9%	18.3%	18.1%	11.8%	2.9%	11.7%	6.0%	16.7%	17.6%	14.4%
11	0.0%	8.0%	5.3%	17.6%	17.5%	8.1%	0.6%	9.7%	4.8%	14.9%	16.3%	11.0%
12	0.0%	4.3%	5.6%	13.8%	13.7%	4.5%	0.0%	6.8%	5.9%	12.3%	11.3%	7.0%

Table 5. RA requirements (i.e., $D_{50}^{m}(1+\alpha_m^*)$) resulting from the CAISOTargetLOLE selection criteria applied to each of the twelve risk-reserve cases.

Month	A	B	C	D	E	F	A'	B'	C'	D'	E'	F'
1	30,755	32,809	33,105	35,855	35,967	32,114	30,755	33,499	32,472	35,105	35,537	32,962
2	30,213	33,587	33,000	36,562	36,516	32,966	30,572	33,293	32,470	34,830	35,008	32,843
3	30,859	34,879	34,094	37,898	38,058	34,168	32,581	35,385	34,204	36,954	37,262	34,862
4	33,625	39,203	38,070	42,342	42,347	38,205	38,371	41,454	39,431	43,194	42,870	40,750
5	37,197	42,640	41,427	45,713	45,631	41,677	40,723	43,972	41,902	45,738	45,440	43,250
6	47,214	47,214	49,258	49,258	51,820	47,043	46,287	46,287	47,221	47,221	49,696	46,420
7	52,616	52,616	55,236	55,236	54,733	52,752	53,253	53,253	54,619	54,619	54,291	53,463
8	52,961	52,961	55,141	55,141	55,958	53,001	53,487	53,487	54,779	54,779	55,273	53,658
9	54,162	54,162	56,078	56,078	57,531	54,579	54,634	54,634	56,069	56,069	57,202	55,106
10	40,036	44,096	41,996	47,346	47,295	43,758	41,207	44,734	42,449	46,710	47,078	44,789
11	33,561	36,257	35,326	39,460	39,450	35,268	33,767	36,832	35,170	38,557	39,039	36,230
12	31,434	32,800	33,204	35,780	35,733	32,230	31,434	33,566	33,290	35,287	34,991	32,994

4. Impact of Risk-Reserve Modeling Assumptions

Different modeling assumptions alter the monthly risk-reserve curves and associated PRMs. In this section, we analyze the impact of various risk-reserve modeling assumptions, as reflected in the risk-reserve case definitions, on the PRMs from the CAISOTargetLOLE selection criteria.

a. Using 1-in-2 Peaks for Reserves That Differ from 1-in-2 of Peaks in Risk Modeling Overstates PRMs

The Energy Division's Draft 2028 PRM Study calculated reserves using both the 1-in-2 peak managed load from the IEPR 2025 forecast and from the 25 weather-year dataset used in the probabilistic reliability model. The 1-in-2 peaks used to calculate the achieved reserve margin of a portfolio should correspond to the load data used to assess the risk of loss-of-load events in the probabilistic reliability model. To do otherwise breaks the connection between the risk and reserves that is fundamental to CalCCA's methodology.

To quantify the implications of using mismatched loads between the risk and reserve sides, we compare the PRM_{ISO} in Case F, which uses the IEPR 2025 peaks to calculate reserves, and Case B, which uses the 1-in-2 managed load peaks from the 25 weather-year dataset used in the probabilistic reliability model. We make the same comparison for Case F' and B', where the ' indicates that capacity is removed from the Baseline by proportional scaling rather than perfect capacity.

Table 6. Using managed peak loads from the IEPR 2025 in reserve calculations, as in Case F and F', overstates PRMs relative to using the 1-in-2 managed peak load from the 25 weather-year data that is used in probabilistic reliability modeling, as in Case B and B'.

Month	F	B	F-B	F'	B'	F'-B'
1	6.2%	6.7%	-0.4%	9.0%	8.9%	0.1%
2	10.8%	11.2%	-0.4%	10.4%	10.2%	0.2%
3	12.7%	13.0%	-0.3%	15.0%	14.7%	0.3%
4	17.1%	16.9%	0.2%	24.9%	23.6%	1.3%
5	28.1%	27.4%	0.7%	32.9%	31.4%	1.5%
6	14.3%	12.2%	2.1%	12.7%	10.0%	2.8%
7	15.2%	12.6%	2.5%	16.7%	14.0%	2.7%
8	17.2%	14.6%	2.6%	18.7%	15.7%	2.9%
9	13.2%	10.7%	2.5%	14.3%	11.7%	2.6%
10	11.8%	10.1%	1.7%	14.4%	11.7%	2.7%
11	8.1%	8.0%	0.0%	11.0%	9.7%	1.3%
12	4.5%	4.3%	0.1%	7.0%	6.8%	0.2%

The difference in the PRMs, as shown in Table 6, shows that using the mismatched IEPR 2025 peak load in the reserve calculations tends to shift the risk-reserve curves to the right (i.e., suggests higher achieved reserve margins are needed to have the same risk of loss-of-load events). Using the mismatched IEPR 2025 peaks therefore overstates the PRMs needed to meet a LOLE of 0.1

events/year by at least 2 percentage points in the months of June-September and as high as 2.9 percentage points in August with the proportional scaling of the Baseline portfolio.

b. Scaling Portfolio or Removing Capacity (NOU) Often Produce Similar Risk-Reserve Curves

Risk-reserve curves differ depending on whether capacity is removed from the Baseline portfolio by removing perfect capacity (Cases A through F) or by proportionally reducing all capacity (Cases A' through F'). However, in most cases we do not see a systematic bias moving all monthly risk-reserve curves one direction or the other. The exception is in the months of April and May, where risk-reserve curves generated from the removal of perfect capacity are shifted to the left relative to risk-reserve curves from proportionally scaling all resources in the Baseline portfolio. The implication is that April and May PRMs calculated by removing perfect capacity will tend to be lower than PRMs calculated by proportionally scaling the Baseline portfolio, as shown in Figure 9.

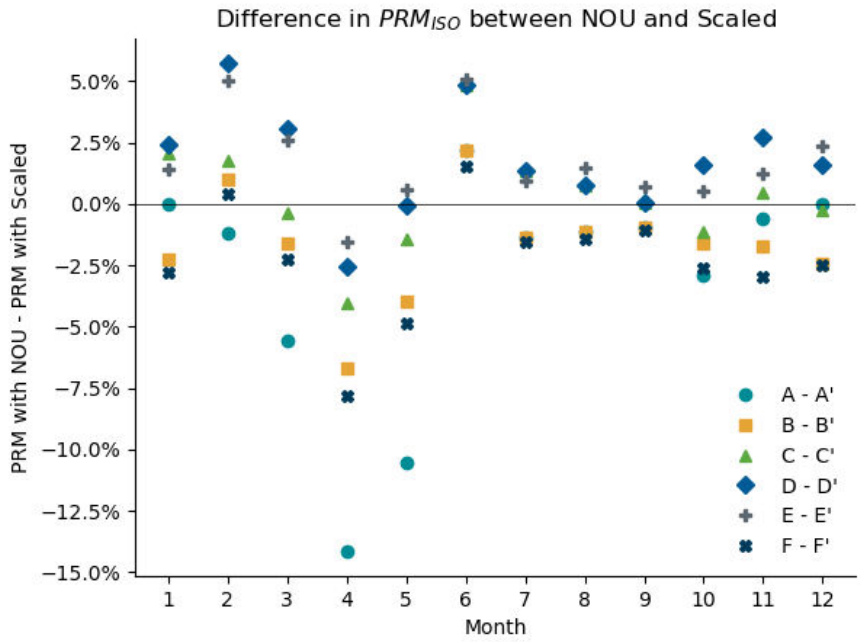


Figure 9. Proportional scaling of the Baseline portfolio or removing perfect capacity (NOU) often produce similar risk-reserve curves, with the exception of April and May.

No matter what level of PRMs are used in the RA program, no element of the RA program design determines whether the uncontracted Baseline capacity will tend to look more like perfect capacity or more like a proportional share of the Baseline portfolio. Consequently, the risk-reserve curves have an inherent uncertainty related to which portion of the Baseline would be shown to meet a given PRM. This analysis helps to bound that uncertainty: the choice likely impacts monthly PRMs by +/- 2.5 percentage points in most cases, with larger impacts in April and May. It does not, however, provide a clear recommendation for how to resolve the inherent uncertainty.

c. Lower PRMs Are Needed if Imports Can Exceed Shown Import RA

Diverse perspectives on the way to handle imports in risk and reserve modeling led to a variety of assumptions in the Draft 2028 PRM studies, particularly for assumptions outside of the peak hours of the summer months. For the peak hours in the summer months, all studies consistently assume that accredited imports in reserve calculations are 4 GW and that the SIL in the probabilistic reliability model is capped at 4 GW (with appropriate scaling of the accredited imports and SIL when using SCE's proportional scaling approach). Outside of this narrow window, however, disagreement stems from whether imports in the probabilistic reliability model can ever exceed the accredited imports shown in RA filings.

Figure 10 shows the PRM_{ISO} can vary, in the most extreme months of April and May, by more than 25 percentage points across different assumptions on import accreditation. While differences in the PRMs are much smaller in the critical months of July through September, only 7 percentage points, these months have historically had the tightest RA supply and highest RA costs.

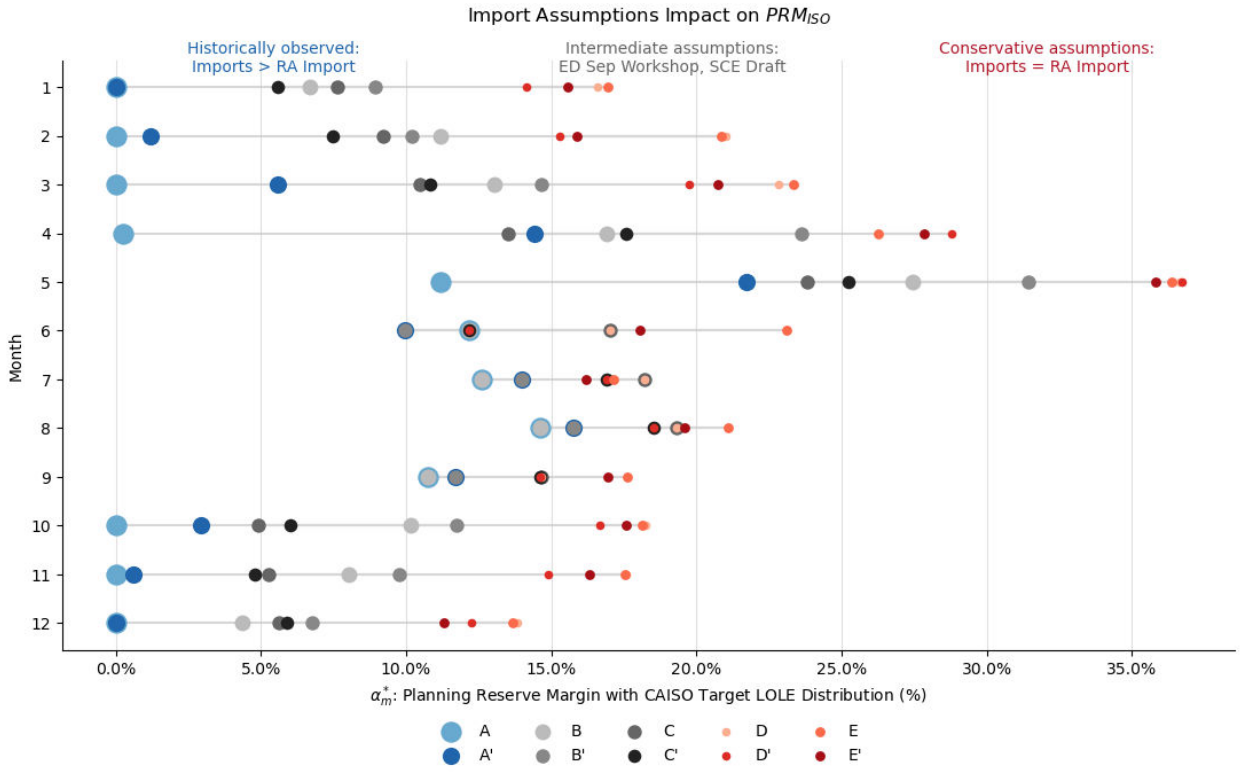


Figure 10. Lower PRMs are needed when risk-reserve curves recognize economic imports—imports that can exceed shown import RA.

Assuming imports in the probabilistic reliability model can never exceed the accredited import RA capacity, as in Cases D, D', E, and E', consistently results in the highest PRM_{ISO}. In contrast, the lowest PRM_{ISO} stems from assuming that available resources outside of the CAISO can be

imported up to Energy Division's SIL even if the shown RA imports are only 4 GW in all months and hours, as assumed in Case A. Case A' does not always lead to as low of a PRM as Case A simply because Case A' scales down both the SIL in the probabilistic reliability model and the accredited import RA capacity in reserve calculations. Scaling lowers the relative impact of imports on achieved reserve margin and risk in portfolio's that define the shape of the risk-reserve curves.

In the summer months, the differences in PRMs across import assumptions are smaller in part because all assumptions agree on limiting the SIL to 4 GW and accrediting import RA capacity at 4 GW in the peak summer hours between HE17 and HE22. Even with this agreement for summer peak hours, however, the summer PRMs still differ across cases. The reason is that off-peak imports play an important role in providing charging energy for storage, which is energy-limited when responding to stressful conditions that drive summer loss-of-load. In the summer, Cases A, A', B and B' allow for some off-peak imports in summer that can, when resources are available in neighboring regions, exceed the shown RA imports and help charge energy storage for stressful conditions during peak hours. Economic imports (i.e., imports that exceed shown RA imports and do not have a CAISO must-offer-obligation) outside of peak hours, are a regularly observed part of the CAISO system. Their importance in supporting CAISO's reliability will only grow as the CAISO system comes to depend more on energy-limited resources. That said, the other reason for the smaller range of PRMs in the summer months is that imports are a relatively smaller portion of the overall portfolio of resources used to keep the CAISO system reliable.

In the non-summer months, however, the 11 GW simultaneous import limit can be roughly a third of the 1-in-2 peak demand, making import assumptions critical to determining PRMs. PRMs are lower in cases that allow some degree of economic imports (i.e., Cases A, A', B, B', C, and C' all allow varying degrees of imports that can exceed shown RA imports). CalCCA's modeling found that surplus resources outside of CAISO could be available to import up to the Energy Division's SIL in all non-summer hours under all weather years (see Appendix B). Relying on the availability of these surplus resources, even LSEs only show 4 GW of RA imports, as in Case A, results in negligible loss-of-load events and non-summer PRMs of 0 percent. Suggesting that economic imports would be sufficient to handle loads above the 1-in-2 peak, variable generation below the exceedance profiles, forced outages, and operating reserve requirements.

While the 0 percent PRMs in non-summer months resulting from Case A are an interesting and thought-provoking result, CalCCA does not recommend using Case A to set non-summer PRMs at this time. Rather, we present these results to highlight the important role of import assumptions in setting PRMs and recommend further discussion and workshops among stakeholders and experts. In the interim, the import assumptions in Case B and B', consistent with the Energy Division's assumptions at the Workshop, appear to be a reasonable middle ground.

A second insight from this analysis is that PRM_{ISO} in April in May should be the highest across all months under that condition that imports can never exceed shown RA imports (i.e., as assumed in

Cases D, D', E, and E'). April and May have moderate 1-in-2 peaks, with a high degree of variability of loads and renewable profiles across weather years. Reliably managing that variability requires high PRMs. However, April and May are also times of the year when surplus resources could be expected to be available in regions outside of the CAISO, increasing the comfort level for reliance on economic imports. The need for high PRMs in April and May quickly disappears when recognizing imports that can exceed shown import RA.

5. Comparison of PRM Selection Criteria

In an RA program that has monthly RA showings, there are many ways to meet the requirement that the annual LOLE be less than or equal to 0.1 events/year. The previous section focused on PRMs that match the CAISO Target LOLE distribution in order to explore the risk-reserve modeling assumptions. In this section we turn to comparing PRM different selection criteria. All of the criteria considered here maintain reliability by meeting a LOLE of 0.1 events/year.

a. PRMs and LOLE for Case B

The differences between PRM selection criteria are easiest to observe with a fixed set of risk-reserve curves, derived from a single set of risk and reserve modeling assumptions. Here we present results using assumptions from Case B, which uses the Energy Division's proposal for accreditation interchange capacity and the SERVM 1-in-2 peak loads in reserve calculations. The PRMs resulting from the eight different PRM selection criteria, applied to the risk-reserve curves from Case B, are shown in Table 7. The corresponding LOLE in each month, which always sums to 0.1 events/year or less, is shown in Table 8.

Several key results with Case B extend to other cases and will be described further in the following sections:

- Annual and Seasonal2 PRMs can go no lower primarily because of the increasing risk of loss-of-load events in May. Loss-of-load events are concentrated in May with these PRM selection criteria.
- Seasonal3 PRMs decouple the PRMs in May and April from other seasons, allowing PRMs in other months to decrease by 3.4 to 5 percentage points relative to the Seasonal2 or Annual PRMs. The May and April Seasonal3 PRMs, on the other hand increase by 11.1 to 11.6 percentage points relative to Seaonal2 or Annual PRMs. The Seasonal3 PRMs shift all of the risk of loss-of-load events to June through September, with the highest concentration in August.
- The MonthlyRACost, AnnualRACost, and MonthlyTotalCostHedged PRMs roughly follow a similar shape to the monthly PRMs from the CAISOTargetLOLE criteria (PRM_{ISO}). Across these criteria and RA price scenarios, PRMs in the months of June through September are in the range of 8.9 to 15.1 percent; which is always lower than the corresponding 17.4 percent Annual or Seasonal2 PRM applicable to the same months. PRMs in May are much higher than the Annual and Seasonal2 PRMs, in the range of 22.1 to 27.5 percent.
- Cost minimizing PRMs are similar to the PRM_{ISO} becasue, for the most part, they concentrate LOLE in the more expensive summer months. The distribution of LOLE most closely matches the CAISO Target LOLE distribution for the PRMs from AnnualRACost and MonthlyRACost with RA prices from the 2023 RA Market Report, featuring severely peaked RA prices in September.

- An exception is that as the shape of RA prices flatten, with the 2027 MPB Forecast assuming equal RA prices across all months, the LOLE also becomes more widely distributed. In fact with the completely flat prices assumed with the 2027 MPB Forecast, the MonthlyRACost PRM selection criteria finds greatest cost savings by lowering the PRM in April, a month with a shallow risk-reserve curve, and as a result, increasing the concentration of loss-of-load events in April.

Table 7. Comparison of PRMs selected from different criteria, but all meeting a LOLE of 0.1 events/year or less, using risk-reserve curves from Case B.

PRM Selection Critera	RA Prices for PRM Problem	1	2	3	4	5	6	7	8	9	10	11	12
Annual		17.4%	17.4%	17.4%	17.4%	17.4%	17.4%	17.4%	17.4%	17.4%	17.4%	17.4%	17.4%
Seasonal2		16.9%	16.9%	16.9%	16.9%	17.4%	17.4%	17.4%	17.4%	17.4%	16.9%	16.9%	16.9%
Seasonal3		13.5%	13.5%	13.5%	27.5%	27.5%	12.4%	12.4%	12.4%	12.4%	13.5%	13.5%	13.5%
CAISOTargetLOLE		6.7%	11.2%	13.0%	16.9%	27.4%	12.2%	12.6%	14.6%	10.7%	10.1%	8.0%	4.3%
AnnualRACost		5.7%	11.3%	11.7%	16.9%	27.5%	15.4%	14.0%	15.2%	8.9%	12.5%	7.1%	4.4%
MonthlyRACost	2023 RA Market Report	5.3%	9.1%	10.2%	14.1%	22.3%	12.4%	12.6%	14.9%	11.0%	10.5%	6.1%	0.3%
	2025 FERC EQR	5.0%	8.6%	9.5%	9.1%	22.1%	12.1%	13.2%	15.0%	12.5%	10.5%	5.2%	0.0%
	2027 MPB Forecast	5.0%	8.6%	9.5%	6.9%	22.1%	12.5%	13.6%	15.1%	12.7%	10.6%	5.4%	0.0%
MonthlyTotalCostHedged	2023 RA Market Report	5.2%	8.9%	10.0%	13.5%	22.6%	12.0%	12.4%	14.6%	11.9%	10.5%	5.3%	0.1%
	2025 FERC EQR	4.9%	8.4%	9.1%	13.1%	22.1%	11.6%	12.5%	14.9%	12.4%	10.5%	5.1%	0.0%
	2027 MPB Forecast	4.7%	8.1%	8.8%	12.9%	22.1%	11.7%	12.8%	15.0%	12.5%	10.5%	5.1%	0.0%
MonthlyTotalCostUnhedged	2023 RA Market Report	81.3%	91.0%	94.2%	94.5%	96.9%	45.4%	34.1%	32.9%	25.5%	56.0%	75.6%	73.5%
	2025 FERC EQR	38.1%	42.8%	36.1%	94.4%	96.8%	45.4%	34.2%	32.9%	25.6%	56.0%	75.5%	73.5%
	2027 MPB Forecast	38.2%	42.7%	94.0%	94.4%	96.8%	45.5%	34.2%	33.0%	25.6%	56.0%	75.5%	35.4%

Table 8. Comparison of the monthly distribution of loss-of-load events, as measured by $LOLE_m$, corresponding to PRMs selected from different criteria using risk-reserve curves from Case B.

PRM Selection Critera	RA Prices for PRM Problem	1	2	3	4	5	6	7	8	9	10	11	12
Annual		0.0000	0.0000	0.0000	0.0000	0.0985	0.0000	0.0000	0.0015	0.0000	0.0000	0.0000	0.0000
Seasonal2		0.0000	0.0000	0.0000	0.0000	0.0985	0.0000	0.0000	0.0015	0.0000	0.0000	0.0000	0.0000
Seasonal3		0.0000	0.0000	0.0000	0.0000	0.0000	0.0100	0.0194	0.0571	0.0133	0.0000	0.0000	0.0000
CAISOTargetLOLE		0.0000	0.0000	0.0000	0.0000	0.0000	0.0120	0.0160	0.0160	0.0480	0.0080	0.0000	0.0000
AnnualRACost		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0025	0.0063	0.0911	0.0000	0.0000	0.0000
MonthlyRACost	2023 RA Market Report	0.0006	0.0017	0.0010	0.0030	0.0065	0.0098	0.0169	0.0100	0.0421	0.0039	0.0020	0.0025
	2025 FERC EQR	0.0019	0.0035	0.0037	0.0292	0.0077	0.0122	0.0080	0.0079	0.0118	0.0039	0.0066	0.0036
	2027 MPB Forecast	0.0018	0.0035	0.0039	0.0415	0.0074	0.0090	0.0045	0.0068	0.0092	0.0033	0.0055	0.0036
MonthlyTotalCostHedged	2023 RA Market Report	0.0008	0.0022	0.0017	0.0052	0.0056	0.0131	0.0197	0.0162	0.0224	0.0038	0.0059	0.0033
	2025 FERC EQR	0.0026	0.0048	0.0063	0.0071	0.0077	0.0171	0.0173	0.0095	0.0131	0.0039	0.0070	0.0036
	2027 MPB Forecast	0.0041	0.0072	0.0082	0.0087	0.0078	0.0164	0.0135	0.0082	0.0110	0.0040	0.0073	0.0036
MonthlyTotalCostUnhedged	2023 RA Market Report	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	2025 FERC EQR	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	2027 MPB Forecast	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000

b. PRMs Based on Minimizing RA Costs Are Similar to PRMs from CAISO's Target LOLE Distribution

The resemblance between the PRMs from the RA-cost-minimizing criteria and the PRM_{ISO} means that the total RA costs are similar. As a corollary, the divergence of the Annual and Seasonal2 PRMs from the RA-cost-minimizing PRMs means that the total RA costs will be different. Table 9 shows how much more expensive it is to meet RA requirements with PRMs set without consideration of RA costs relative to the cost of RA with the MonthlyRACost premium using the risk-reserve curves for Case B. In this table RA costs are expected to vary with monthly RA requirements. Table 10 shows

the RA cost premium under the assumption that RA costs instead vary with the highest annual RA requirement, again showing results only for Case B.

Table 9. Increase in RA cost with risk-reserve curves from Case B when selecting PRMs using various non-cost-minimizing criteria compared to the RA cost of PRMs selected using the MonthlyRACost criteria, assuming that RA costs vary with monthly RA requirements.

PRM Selection Criteria	2023 RA Market Report	2025 FERC EQR	2027 MPB Forecast
Annual	5.0%	5.6%	6.1%
Seasonal2	4.9%	5.4%	5.9%
Seasonal3	1.9%	3.2%	4.1%
CAISOTargetLOLE	0.6%	1.2%	1.6%

Table 10. Increase in RA cost with risk-reserve curves from Case B when selecting PRMs using various non-cost-minimizing criteria compared to the RA cost of PRMs selected using the AnnualRACost criteria, assuming that RA costs vary with the highest RA requirement across the year.

PRM Selection Criteria	2023 RA Market Report	2025 FERC EQR	2027 MPB Forecast
Annual	7.8%	7.8%	7.8%
Seasonal2	7.8%	7.8%	7.8%
Seasonal3	3.2%	3.2%	3.2%
CAISOTargetLOLE	1.7%	1.7%	1.7%

The higher summer PRMs with the Annual and Seasonal2 selection criteria require more RA contracts in the summer than the RA-cost-minimizing PRMs and the PRM_{ISO}. As a result, overall RA costs are 4.9 to 7.8 percent higher with the Annual and Seasonal2 PRMs even though all of the PRM criteria meet the same level of reliability, as reflected by the LOLE of 0.1 events/year or less. In absolute terms, the Annual and Seasonal2 PRMs could have RA costs that are $290-597 million/year higher than RA-cost-minimized PRMs.

The CAISOTargetLOLE selection criteria also results in RA costs that are higher than the RA-cost-minimized PRMs. However, the closer resemblance of the PRMs means that the RA cost premium of PRM_{ISO}, using risk-reserve curves from Case B, is only 0.6 to 1.7 percent, or $33-130 million/year, above the RA cost for the RA-cost-minimized PRMs.

These results: (1) that the RA costs from the PRM_{ISO} are most similar to the RA-cost-minimizing PRMs; and (2) that the Annual and Seasonal2 PRMs are higher cost, extends to nearly all risk-reserve cases and combinations of RA prices, as shown in Figure 11. At worst, the PRM_{ISO} result in RA costs that are 2 percent higher than the RA-cost-minimizing PRMs. In contrast, the cost of PRMs using the Annual or Seasonal2 criteria can be up to 12 percent higher than the RA-cost-minimizing PRM.

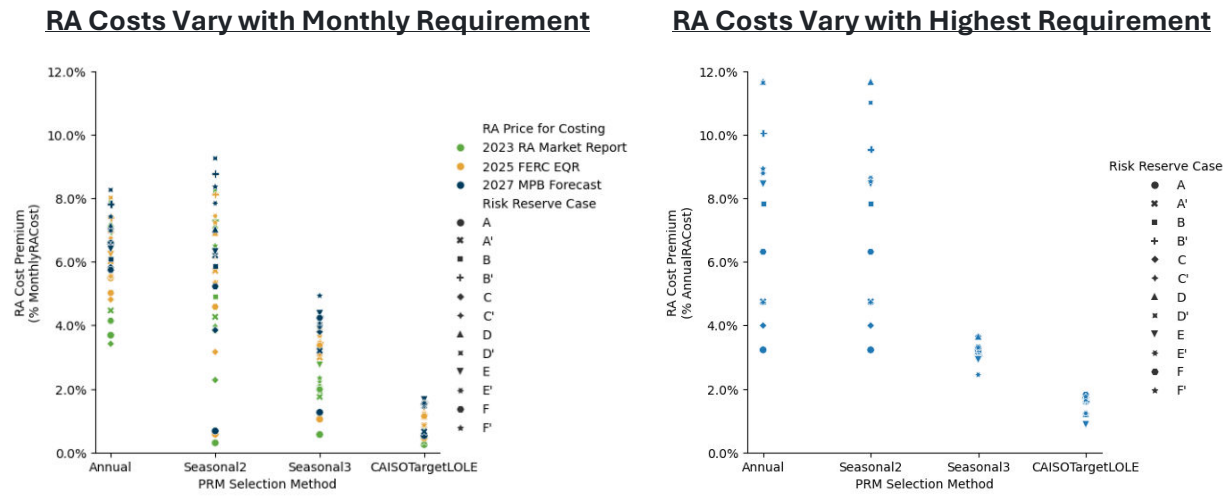


Figure 11. Increase in RA cost with risk-reserve curves from all cases when selecting PRMs using various non-cost-minimizing criteria assuming costs vary with (a) monthly RA requirements or (b) with the highest RA requirement across the year.

c. PRMs with Lower Cost Avoid Grouping High-Variability Months with Summer Months

The high RA cost of the Annual and Seasonal2 PRMs across a wide range of cases is often driven by a fact observed earlier with the risk-reserve curves from Case B. The high variability in the spring months of April and May, reflected by risk-reserve curves that are shifted to the right relative to other months, often restricts how low PRMs can go before hitting the 0.1 events/year limit. Energy Division's choice to group the high variability month of May with the other summer months in the Seasonal2 PRM selection criteria means that September's PRM is influenced more by conditions in May than it is conditions in September.

The Sesaonal3 selection criteria reduce RA costs by decoupling the PRMs in the high-variability months from the PRMs in the high RA cost months. The PRMs in the spring season are now free to be set a level high enough to avoid loss-of-load events, while PRMs in the more-narrow definition of the summer season are independently reduced to the point where nearly all loss-of-load is concentrated in the summer.

Continuing this logic, why stop at three seasons? Why not go to monthly PRMs where the unique characteristic of each month's risk-reserve curve can be used to inform the choice of monthly PRMs? The monthly RA-cost-minimizing PRMs do just that, resulting in the lowest possible RA costs while still meeting a LOLE of 0.1 events/year. It is worth noting, however, that the annual reliability constraint still couples the decision each month's PRMs together, just in a way that makes tradeoffs more explicit.

d. Exposure to Energy Market Costs Is Managed By LSEs; Should Not Be Used to Set Reliability-Based PRMs

To this point we have focused primarily on RA-cost-minimizing PRMs. We could also consider a broader definition of consumer costs that adds expected energy costs and expected unserved energy costs to the RA costs.

Energy market prices depend on the set of resources participating in the CAISO market. Keeping the managed load constant while removing resources from the Baseline portfolio, either through removal of perfect capacity or proportional reduction of all resources, can increase energy market prices, inclusive of Cap-and-Invest GHG emission costs, if the affected resources are infra-marginal. As such, a reduction in the achieved reserve margin not only increases the risk of unmet energy it also increases the expected energy market costs. Expected energy market costs, defined as the product of energy market prices and managed load, can be two to three times higher than RA costs. Valuing expected unmet energy at a VOLL of over $67,000 MWh similarly provides a strong signal to not lower PRMs too much, though this is already a consideration when requiring that PRMs achieve a LOLE of 0.1 events/year.

If we were to assume that consumers are fully exposed to energy market prices, in other words completely unhedged, then the PRMs from the MonthlyTotalCostUnhedged selection criteria would be set so high that all or nearly all of the Baseline portfolio would have to participate in the CAISO market throughout the year. Under such high PRMs, no loss-of-load events would occur, and LOLE would be zero in all months.

Figure 12 illustrates how assuming energy market costs are unhedged drives the total-cost-minimizing PRM in September to over 25 percent, well above the achieved reserve margin where loss-of-load events would begin to occur.

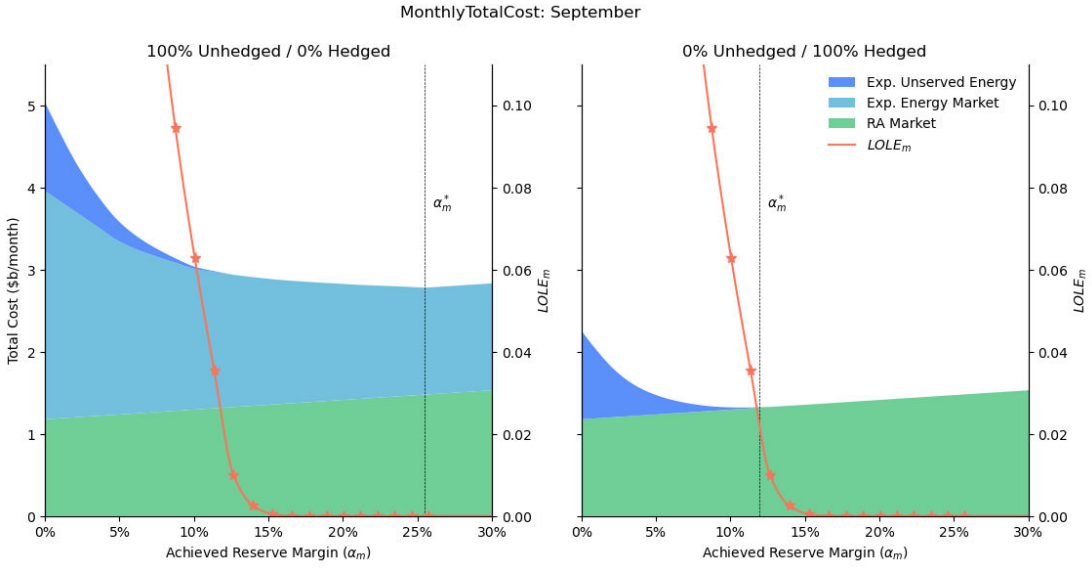


Figure 12. The unreasonable assumption that energy market costs are completely unhedged leads to high PRMs, with no loss-of-load events even in September, under the MonthlyTotalCostUnhedged selection criteria.

The reality is that LSEs use risk-management strategies to limit customer exposure to energy market prices, and these strategies can include financial, energy-only contracts. The achieved reserve margin is therefore not a direct determinant of customer energy market costs, at least in the short term between PRM study and RA program filings,[29] whereas it is more directly linked to expected unserved energy and RA costs.

In as much as LOLE and EUE are related, the MonthlyRACost PRM selection criteria already accounts for the relationship between achieved reserve margin and RA costs along with the relationship between achieved reserve margin and expected unserved energy costs. As such, we would expect that PRMs from the MonthlyRACost and MonthlyTotalCostHedged to be nearly equivalent. Figure 13 shows that across almost all months, risk-reserve cases, and RA price assumptions the PRMs from the MonthlyTotalCostHedged criteria are within +/- 2 percentage points of the PRMs from the MonthlyRACost. Exceptions to this finding primarily occur in April, where the MonthlyRACost criteria sometimes finds RA cost savings from the shallow risk-reserve curve, and to a lesser extent in June. The higher April PRMs with the MonthlyTotalCostHedged criteria indicate that the potential for reducing April RA cost are not worth the potential higher cost of unserved energy in other months like September.

[29] In the long-run, where existing generators may retire or new generators may be built, even the cost of financial (non-RA) energy products may be influenced by PRM decisions. In such a case, a more comprehensive examination of investment and retirement decisions could be used to evaluate PRM selection criteria, similar to a 2014 Brattle study of PRMs for ERCOT (*Estimating the Economically Optimal Reserve Margin in ERCOT*, https://www.ercot.com/files/docs/2017/05/16/Estimating_the_Economically_Optimal_Reserve_Margin_in_ERCOT_Revised.pdf). California's RA program is different, however, in that PRMs under consideration for this study would only be in effect for 2028 and 2029, arguably too short of a horizon for long-run effects to impact the cost of financial products to hedge energy market costs.

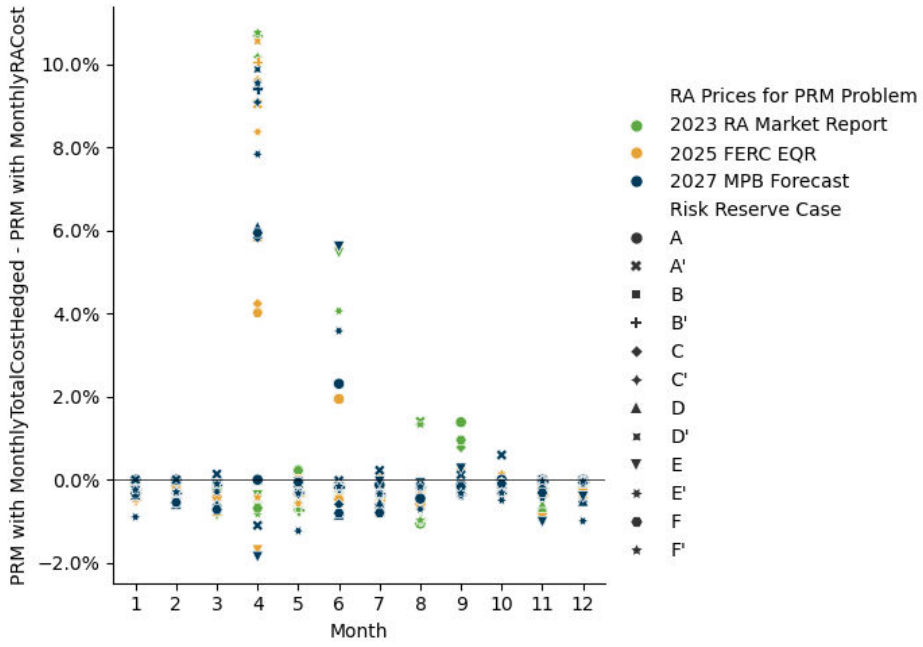


Figure 13. PRMs selected with consideration of RA costs and expected unmet energy costs, following the MonthtlyTotalCostHedged criteria, are similar to the PRMs that only minimize RA costs, MonthlyRACost, because both are required to meet a LOLE of 0.1 events/year.

e. All PRMs Meet 0.1 LOLE But Produce Mixed Results with Other Reliability Metrics

By design, all of the PRM selection criteria meet a LOLE of 0.1 events/year but that does not mean they perform equally when measured with other reliability metrics like the expected loss-of-load hours (LOLH) or expected unserved energy (EUE). Slight differences between LOLE and EUE metrics, coupled with differences in RA costs and the VOLL, in part explain the variation in PRMs selected with the MonthlyRACost and MonthlyTotalCostHedged criteria in the previous section. Table 11 shows the average and maximum of the annual risk metrics across all cases and RA price scenarios for each PRM selection criteria. While the PRM selection criteria are equivalent in meeting a LOLE of 0.1 events/year, the CAISOTargetLOLE criteria and MonthlyTotalCostHedged criteria produce the lowest LOLH and EUE.

Table 11. PRM selection criteria all meet a LOLE of 0.1 events/year but differ on performance on other reliability metrics on average across cases (a) and in the maximum across cases (b).

Average Across Cases and RA Price Scenarios

PRM Selection Criteria	LOLE events/year	LOLH hours/year	EUE GWh/year
Annual	0.1000	0.2226	0.9159
Seasonal2	0.1000	0.2285	0.9639
Seasonal3	0.1000	0.1516	0.5689
CAISOTargetLOLE	0.0994	0.1410	0.4349
AnnualRACost	0.1000	0.1882	0.8316
MonthlyRACost	0.1000	0.1905	0.7894
MonthlyTotalCostHedged	0.0997	0.1444	0.3297
MonthlyTotalCostUnhedged	0.0000	0.0000	0.0000

(a)

Maximum Across Cases and RA Price Scenarios

PRM Selection Criteria	LOLE events/year	LOLH hours/year	EUE GWh/year
Annual	0.1000	0.2818	1.3663
Seasonal2	0.1000	0.2987	1.4252
Seasonal3	0.1000	0.1898	0.8726
CAISOTargetLOLE	0.1001	0.1887	0.7372
AnnualRACost	0.1000	0.2831	1.3065
MonthlyRACost	0.1000	0.2605	1.3958
MonthlyTotalCostHedged	0.1000	0.1746	0.5031
MonthlyTotalCostUnhedged	0.0000	0.0000	0.0000

(b)

Overall differences in risk metrics across PRM selection criteria are likely smaller than differences in PRMs that would arise if a reliability target other than a LOLE of 0.1 events/year were to be used. Brattle and Astrape (2013),[30] for example, shows how PRMs change if the reliability standard is a LOLE of 0.1 events/year, an LOLH of 2.4 hours/year, or a normalized EUE of 0.0010 percent. In the context of the current study, the maximum EUE of 1.4252 GWh/year in Table 11 translates to a normalized EUE of 0.0007 percent. Had we used a normalized EUE of 0.0010 percent as the reliability target in the PRM selection criteria, rather than a LOLE of 0.1 events/year, then all of the PRMs would be lower and all of the resulting LOLEs would exceed 0.1 events/year. Hence, defining a consistent reliability target is more impactful than evaluating PRM selection criteria on differences in off-design risk metrics.

[30] *See* Brattle and Astrape, *Resource Adequacy Requirements: Reliability and Economic Implications* (2013), at 38-41, https://www.ferc.gov/sites/default/files/2020-05/02-07-14-consultant-report.pdf.

6. Recommendations

At the outset of this effort, CalCCA set out not to identify a specific PRM for 2028, but instead to ask Energy Division to include affordability in its consideration of PRMs when multiple options produce the same level of reliability. In CalCCA's I&As, we developed a consistent framework for explicitly including RA costs in the PRM selection criteria, along with a step-by-step process for implementing the framework using tools and data already in use by the Energy Division. With this Final 2028 PRM Study, CalCCA has now demonstrated the process and used the results to quantify tradeoffs between different PRM selection criteria.

a. Adopt CalCCA's Approach to Generating Monthly Risk Reserve Curves and Cost-Minimizing PRM Selection Criteria

CalCCA's approach provides a pathway to lower electricity costs for customers while maintaining reliability, links PRMs to a transparent and consistent process, and generates datasets, namely risk-reserve curves, that enable stakeholders to evaluate a wide range of alternative PRM selection criteria. With this, we come back full circle to our primary recommendation: the CPUC should adopt CalCCA's approach to generating monthly risk-reserve curves and comparing PRMs stemming from different selection criteria in its PRM studies. PRMs from CalCCA's cost-minimizing selection criteria (*e.g.*, MonthlyRACost, AnnualRACost, or MonthlyTotalCostHedged) can then be used to provide an affordability benchmark for any other PRM proposals.

While cost-minimization should not be the only criteria driving PRM selection, it should be one consideration included among other insights or factors driving PRM selection. We acknowledge that determining PRMs is an art as well as a science. However, if proposed PRMs drive up RA costs, well above the cost-minimizing benchmark, there should be clear reasoning for why paying that higher cost is justified. Across a wide range of scenarios and assumptions, we see no clear justification for using the Annual or Seasonal2 PRM selection criteria as they are currently defined. The peak summer month PRMs (July-September) should not result from an approach that arbitrarily ties those PRMs to the PRMs needed to manage high-variability months (e.g., April, May). Grouping May with the peak summer months results in an increase in the PRMs in the peak months and higher RA cost, without improving reliability relative to other options.

Our study also reveals an area that feels a little too much like art without enough science: the choice of import assumptions in probabilistic reliability modeling and reserve calculations. Draft studies used differing import assumptions without a clear recognition of the implications for PRMs. This study shows that different assumptions can have significant impacts on PRMs and that the most conservative assumptions deviate from observed system operations. We see that the Energy Division's proposal is a reasonable middle ground as an interim solution, and recommend Energy Division host workshops on import assumptions prior to the next PRM study. The workshops should directly consider the question of what role energy-only economic imports, a mainstay of

CAISO operations, should play in reliability modeling, especially as the system continues to both better integrate with neighboring regions and incorporate a greater share of energy-limited resources like battery storage.

Other outstanding modeling questions affect PRMs in meaningful ways, but do not need to wait for future workshops to resolve. The Commission should accredit conventional resources when setting PRMs using the UCAP EFORd+Ambient approach, rather than installed capacity (ICAP). The UCAP EFORd+Ambient approach aligns accreditation in reserve calculations with the accreditation rules that will be in place for the 2028 RA program. The Commission should also use the 1-in-2 peak load of the 25-weather year dataset (SERVM) instead of 2025 IEPR peaks to calculate reserves in the PRM setting process. Establishing a relationship between a portfolio's risk of unmet demand and its achieved reserve margin expects that the managed load used in probabilistic reliability modeling corresponds to the 1-in-2 peak managed loads used to calculate reserves. While we appreciate the engagement of ED staff raising the question of whether energy market costs should be considered on par with RA costs when considering affordability, we've now shown why the unique ability of LSEs to hedge exposure to energy market costs through non-RA products means it is not appropriate to set PRMs using unhedged expected energy costs.

Independent of the particular modeling assumptions, the CAISOTargetLOLE PRM criteria performed well in terms of affordability. Other advantages of using the CAISOTargetLOLE PRM criteria include using criteria defined by the grid operator, being relatively easy to understand, and being easy to implement once risk-reserve curves are defined. It also keeps the distribution of the LOLE across the year fixed, even across different modeling assumptions, and concentrated in the peak summer months. For now, the PRMs from the CAISOTargetLOLE tend to agree with the cost-minimizing PRMs. In future years, as RA prices, demand, and supply evolve, it is possible PRMs will not agree to the same degree. At which point benchmarking to cost-minimizing PRM selection criteria could reveal the need to change the target LOLE distribution or shift to other criteria altogether.

b. Select PRMs Using CAISO Target LOLE Criteria with Assumptions Consistent with Case B

For the 2028 PRMs, CalCCA recommends using the CAISOTargetLOLE PRM selection criteria in conjunction with risk-reserve curves from Case B. These assumptions allow Energy Division to continue to identify loss-of-load events by removing perfect capacity, consistent with its existing methodology, and will result in monthly PRMs that range from 4-15 percent across most months with PRMs as high as 16-27 percent only in April and May. The final recommended PRMs are shown in Figure 14.

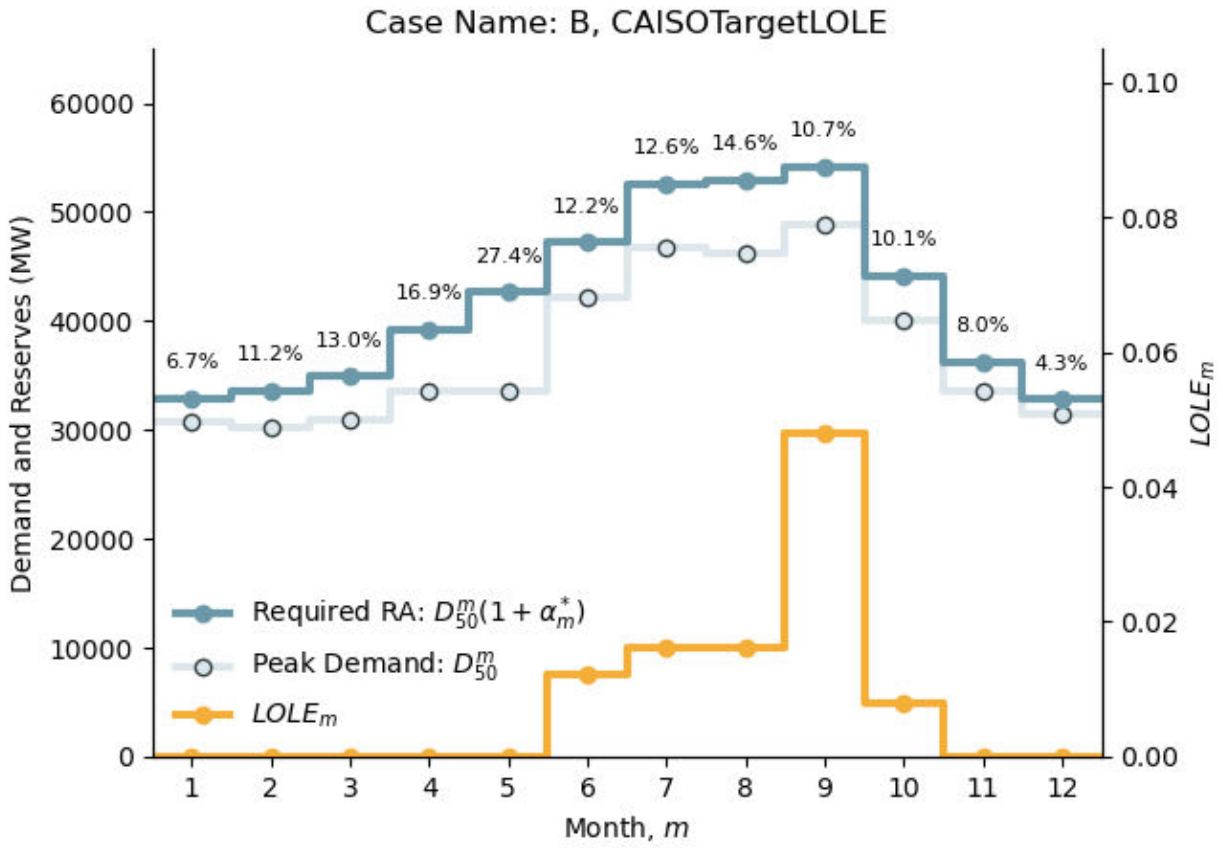


Figure 14. CalCCA recommends 2028 PRMs selected using the CAISOTargetLOLE criteria with risk-reserve curves from Case B.

With these PRMs, the RA requirements are highest, exceeding 52 GW during the tightest hours, in the months of July, August, and September due to the high 1-in-2 peak managed load. According to the CAISO Target LOLE distribution, 80 percent of the LOLE is concentrated in these high-requirement months. The concentration of LOLE allows the PRMs to stay between 10.7 to 14.6 percent, or 2.8 to 6.7 percentage points lower than it would have otherwise been with an Annual or Seasonal2 PRM that meets the same LOLE of 0.1 events/year across the year. Even though RA cost is not directly considered in the CAISOTargetLOLE criteria, choosing PRMs with the CAISOTargetLOLE selection criteria can reduce RA costs by 4.0 to 5.7 percent under modeling assumptions consistent with Case B.

The recommended PRMs are significantly higher than Annual or Seasonal2 PRMs in April and May. However, the moderate 1-in-2 peak loads in the spring mean the RA requirements in those months remains below 44 GW. Historical observations of economic imports in April and May suggests that the RA requirements in those months could be lower without sacrificing reliability. Additionally, April and May PRMs were less than 18 percent in April and May of 2025 and 2026, without any obvious reliability concerns, though we do not yet know what the achieved reserve margin was for those months under the SOD accounting rules. Until further data and analysis are available, it is

prudent to recommend April and May PRMs that are high enough to avoid unmet energy under the assumptions in Case B.

The combination of moderate PRMs and low 1-in-2 peak demand in the months of November through March keep RA requirements in those months below 37 GW. This period of lower RA requirements creates a contiguous five-month period suitable for planned maintenance of generating resources, without detrimental impacts to reliability.

Overall, CalCCA's recommended PRMs achieve significant reductions in consumer costs of complying with RA requirements while still ensuring that the system has sufficient resources to meet a LOLE of 0.1 events/year.

Appendix A. Probabilistic Reliability Model Assumptions

- Load:
    - CAISO hourly net managed load profiles based on the Commission's 25 weather years;[31] and
    - Load forecast uncertainty represented by five discrete outcomes spanning -2 percent to +2 percent, with probability of each outcome from a Midcontinent Independent System Operator (MISO) study.[32]
- Operating Reserves:
    - Operating reserves include 3 percent of hourly net managed load for spinning reserves and 3 percent for regulation up reserves, load shed to maintain reserves;[33] and
    - Storage must maintain sufficient energy to sustain spinning reserve deployment for one hour and regulation up reserves for ten minutes.[34]
- Conventional Resources and Energy Storage:
    - Resource categories represented by sets of identically sized units, with each unit having a unique forced outage profile;.[35]

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[31] CAISO net managed load created by summing the "NetLoad" columns for the "PGE", "SCE", and "SDGE" regions. Data included Hourly load components for California regions only, 2000-2024 weather, medians consistent with 2025 IEPR demand forecast Planning Scenario, 2028. *See* CPUC System Reliability Modeling Datasets, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/energy-modeling/servm-inputs-2026.

[32] *See* CalCCA Alternative I&A Document, at 23, Table 2 (Load forecast error based on U.S. economic forecast errors from MISO PRM study).

[33] CalCCA's assumption that load shedding is used to preserve operating reserves equivalent to 6 percent of the managed net load is consistent with the Commission's modeling requirement that resources must maintain regulating reserves at 3 percent of load in addition to spinning reserves at 3 percent of load. *See* Revised Inputs & Assumptions SERVM 2026 Data Updates in Support of Resource Adequacy (RA) and Integrated Resource Planning (IRP) (June 5, 2026) (CPUC I&A), at 39-40, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M608/K310/608310037.PDF.

[34] CalCCA's requirement that storage must have energy stored sufficient to maintain the provision of operating reserves is similar to the Commission's definition that "[f]or storage resources, the operational range from the current operating level to maximum output (headroom) and maximum charging (footroom) is available, subject to constraints on energy availability." *See* CPUC I&A, at 38. However, the Commission does not define the time period over which the reserves must be able to be deployed to calculate the energy availability.

[35] The capacity of each identical unit is the total January NQC capacity of the category divided by the number of units in the category. The capacity and count of units are from the "Value" column in the "SERVM Units" tab of the Commission's PRM Calibration Workbook for September 15, 2026 (PRM Calibration Workbook), downloaded from: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-history. CalCCA used the NQC value for conventional resources rather than nameplate to emulate Energy Division's suggestion that some generation, particularly cogen units, cannot operate at their nameplate. Energy Division's Draft 2028 PRM Study, at 12.

    - Forced outages simulated using category-specific forced outage rates from the Commission[36] and assuming 24-hour mean repair time;
    - 3,125 random samples of forced outages (25 for each weather year and load forecast error combination);
    - Category-average thermal derates modeled using hourly weather-dependent derate profiles based on Commission's 25 weather years;[37] and
    - Battery duration based on the average duration of all CAISO battery storage in the Commission's June 2026 Baseline Generating List, with pumped hydro storage duration assumed to be 10 hours.
- Variable and Hydro Resources:
    - Variable Energy Resource (VER) output represented through weather-dependent production profiles without separate forced outage modeling, based on Commission's 25 weather years;[38]
    - Hydro constrained by weather-dependent capacity, monthly energy budgets, and minimum flow requirements;[39] and
    - Emergency hydro, additional hydro capacity that can be called on for limited events, has a maximum capacity that varies with month and year based on the Commission's 25 weather years.[40]
- Transmission:
    - Internal CAISO transmission constraints not modeled;
    - Imports from neighboring regions limited by a Simultaneous Import Limit (SIL) that depends on the case, as described in the next section; and

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[36] Category-average forced outage rates are from the "EFFECTIVE EFORD EXCLUDING AMBIENT DUE TO TEMPERATURE" column of the "Resource Type UCAP" tab in the PRM Calibration Workbook.

[37] CalCCA used the nameplate capacity of each unit to create a capacity-weighted average of the thermal derate by category. Individual unit thermal derates by year are from the Commission's Ambient Temperature Output Derating, 2000-2024 weather, downloaded from https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/energy-modeling/servm-inputs-2026.

[38] VER profiles are consistent with the PRM Accreditation Workbook categories created by summing the columns for the "PGE", "SCE", and "SDGE" regions. See Variable Gen Hourly Profiles, 2000-2024 weather, Baseline Generator List, 2028, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/energy-modeling/servm-inputs-2026.

[39] Hydro parameters created by summing each variable for the "PGE_Hydro_V0024", "SCE_Hydro_V0024", and "SCE_Hoover_Hydro_V0024" unit names in SERVM Hydro Variables, 2000-2024 hydro conditions, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/energy-modeling/servm-inputs-2026. PLEXOS uses a mid-term (MT) schedule to create a coarse plan for allocating hydro across the month based on a load duration curve with 15 blocks. The short-term (ST) schedule then refines the hydro dispatch based on observed hourly conditions.

[40] Emergency hydro capacity created by summing the "capmax" variable for "PGE_Emergency_Hydro_V0024" and "SCE_Emergency_Hydro_V0024" unit names. The maximum energy that can be used by emergency hydro each month is from the corresponding "max_flex" global variable. To model the "borrowing" of emergency hydro energy from the normal hydro budget, CalCCA imposed a constraint that the normal and emergency hydro generation must not exceed the total monthly energy in the "hydro_energy" variable.

    - Imports from neighboring regions dependent on the availability of residual supply after meeting the neighbor's own demand, with additional details in Appendix B.
- Reliability Assessment:
    - Risk of unmet demand quantified through probabilistic simulation of weather, load uncertainty, resource availability, and operating reserve requirements;
    - Risk metrics include expectations of loss-of-load event days[41], loss-of-load hours, and unmet energy.

[41] Consistent with our understanding of the Commission's approach, we assume that any day with unserved energy counts as one loss-of-load event. The monthly LOLE is the probability-weighted average count of events across all days of the month. The LOLE across the year is the sum of each month's LOLE. The reliability standard is to meet a 0.1 LOLE across the year.

Appendix B. Simplified Representation of Neighboring Regions

CalCCA's Draft Study assumed 4 GW of imports in every hour and month, with no consideration of whether resources outside of CAISO could supply the imports. Energy Division's SERVM model instead explicitly represents supply, demand, and transmission constraints for neighboring regions, then applies a simultaneous import limit (SIL) that caps available impots. CalCCA's Final Study modifies PLEXOS to include a simplified representation of supply availability in neighboring regions and then caps available imports with a SIL.

To maintain reasonable solution times and a simple model structure, CalCCA's simplified representation of neighboring regions uses heuristics to estimate residual supply—an hourly accounting of resource availability in excess of the region's demand—instead of directly incorporating unit-by-unit dispatch decisions into PLEXOS. As shown below, the residual supply is suitable for modeling reliability metrics in CAISO, because residual supply is often far greater than the SIL. This implies assumptions about the SIL are likely more important than details on individual generator dispatch decisions. The four sections that follow describe CalCCA's definition of neighboring regions, approach to calculating residual supply, adjustments to residual supply through a regional reliability calibration, and the treatment of unmet demand outside CAISO.

Neighboring Regions

CalCCA's representation of neighboring regions is as follows:

- CalCCA starts with the balancing authority areas (BAAs) modeled by Energy Division, then combines strongly interconnected BAAs into larger aggregated regions;
- CalCCA retains NCNC, IID, and LADWP; and aggregates the remaining BAAs into a NW and SW region shown in Table 12;
- CalCCA aggregates the Energy Division's 25 weather year data for each of the members of a region.

Table 12. CalCCA aggregation of neighboring regions

Aggregate Region	Member Balancing Authority Areas
NW	BPAT, PACW, PortlandGE
SW	AZPS, SRP, NEVP, WALC
NCNC	NCNC
IID	IID
LADWP	LADWP

In PLEXOS, transmission capacity limits transfers between neighboring regions, including the CAISO SIL. Transmission limits are shown in Figure 15.

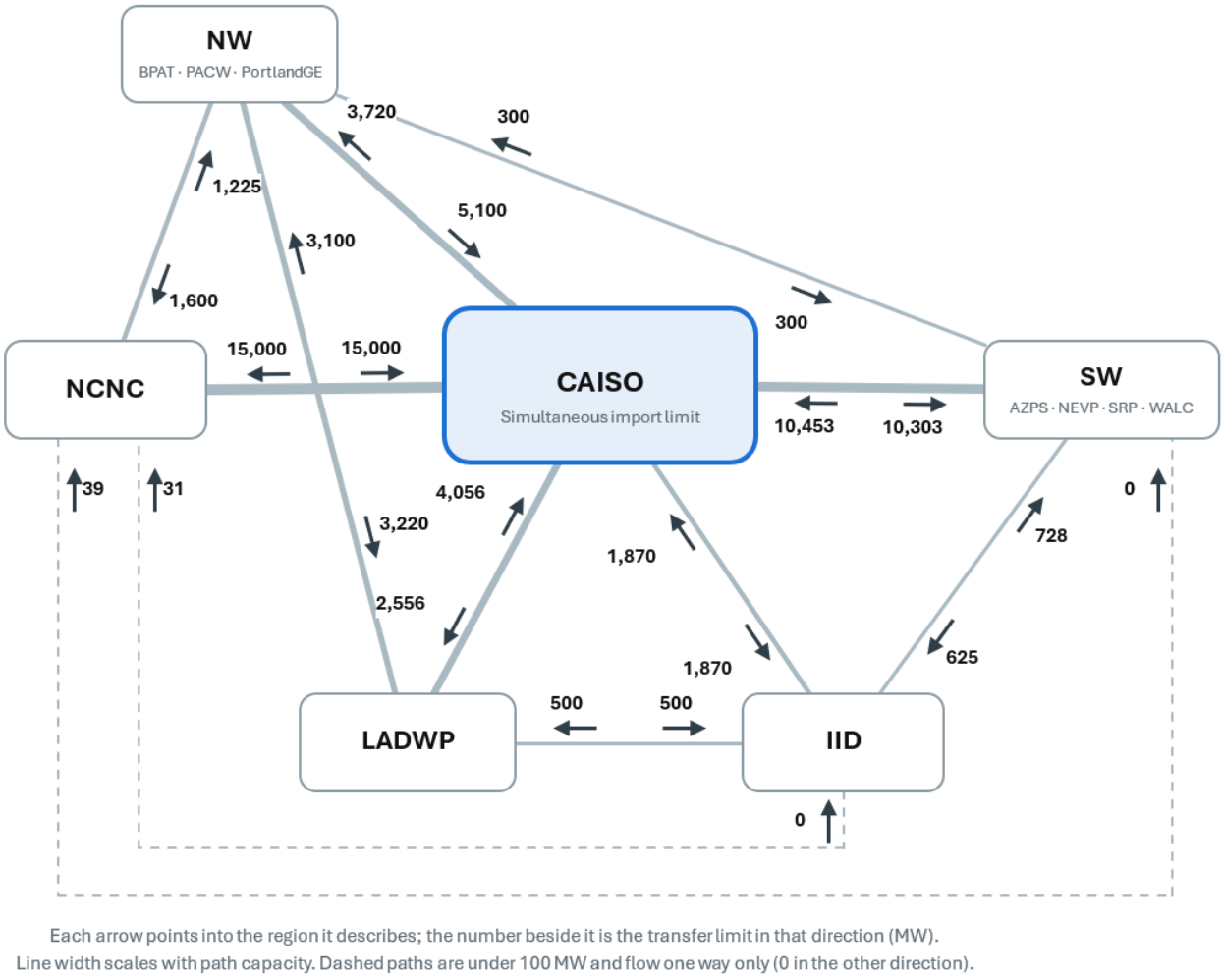


Figure 15. Transmission topology and directional transfer limits between CAISO and the non-CAISO aggregate regions represented in PLEXOS. Total imports into CAISO are further limited by the simultaneous import limit.

Residual Supply

Outside of PLEXOS, CalCCA uses the Energy Division's data along with simple heuristics to calculate residual supply---the supply remaining after meeting each region's weather-dependent managed load and operating reserves. This residual supply, adjusted with a calibration step described in the next section, is incorporated into PLEXOS as an hourly profile for a regional generator that varies over the 25 weather years. The residual supply from one region can supply unmet demand in other regions or can be imported into CAISO, subject to transmission limitations.

Residual supply is the difference between the calibrated firm capacity and the region's managed load and operating reserve requirement, net of any variable energy resources (VER), hydro, and storage. An example calculation of the residual supply for the SW region is shown in Figure 16.

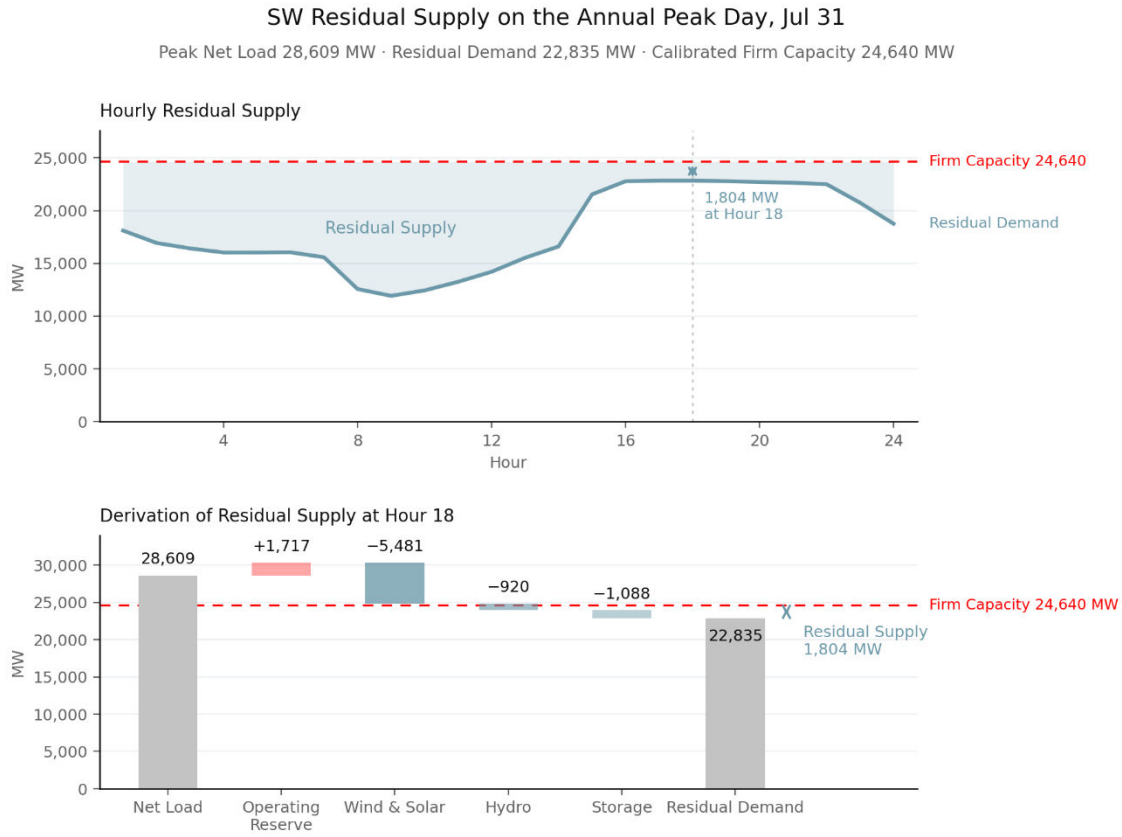


Figure 16. Residual supply on the SW peak day (July 31, weather year 2000), with the peak-hour calculation shown as waterfall. At hour 18, SW's 28,609 MW managed load plus a 1,717 MW operating reserve, less 5,481 MW of wind and solar, 920 MW of hydro, and 1,088 MW of storage, leaves 22,835 MW of residual demand. Against 24,640 MW of calibrated firm capacity with 7.4 percent derate applied, 1,804 MW remains as residual supply.

Each of the components of the residual supply are described below.

- Managed Load:
  - Use Energy Division 2028 25-weather year, hourly managed load by balancing authority, net of behind-the-meter photovoltaics and adjusted for additional achievable energy efficiency and fuel substitution, consistent with CAISO.
- Operating reserve:
  - 6 percent of the hourly managed load.
- Wind and Solar:
  - Reduce managed load by Energy Division's 25 weather year, hourly wind and solar profiles for each region.

- Hydro:
    - Use heuristic to dispatch hydro within the Energy Division's monthly energy budgets and minimum/maximum flows by weather year.
    - Use a simple search algorithm to find a monthly threshold where hydro is at the min flow when the load less wind/solar is below the threshold, and at its max flow (or the max needed to meet demand) when load less wind/solar is above the threshold. Choose the threshold such that the hydro dispatch matches the monthly energy budget. The heuristic is illustrated in Figure 17.

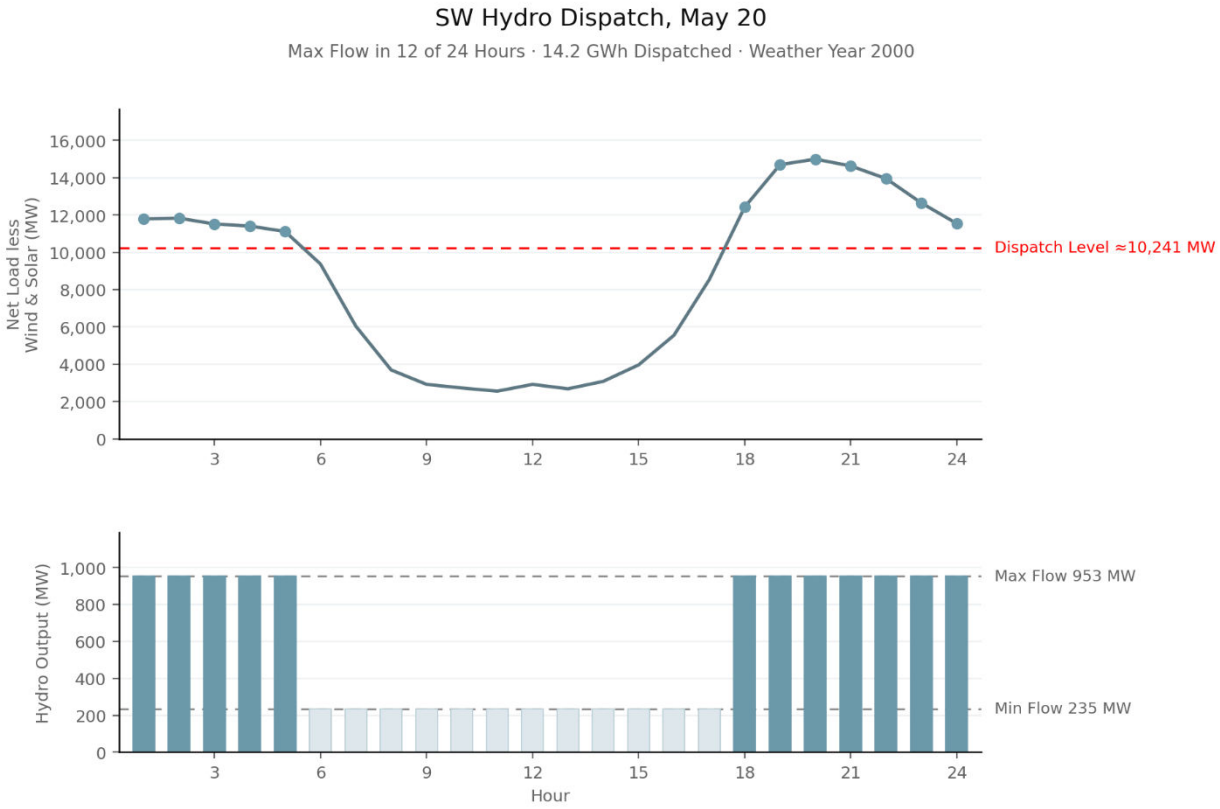


Figure 17. Illustration of heuristic used to dispatch hydro in each region within min flow, max flow, and monthly energy budget constraints.

- Storage:
    - Use a peak-shaving heuristic to dispatch storage to minimize peaks in the load less wind, solar, and hydro profile.
    - Dispatch is constrained by power and energy limits and accounts for an 81 percent round-trip efficiency. An example of storage dispatch is shown in Figure 18.
    - Peak-shaving algorithm is based on a five-day window that is rolled forward one day at a time, and only the dispatch of the middle day of the window is kept. The surrounding days establish state of charge, which reduces boundary effects for the

middle day. Using a rolling window limits processing time across the five regions and 25 weather years.

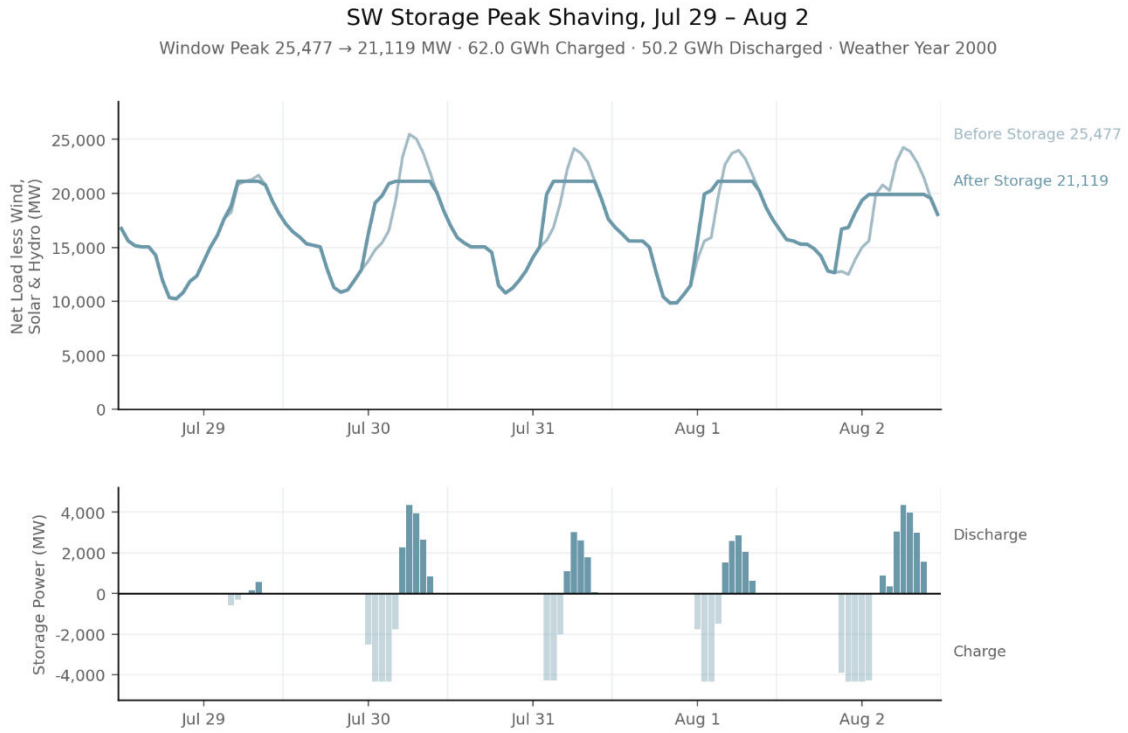


Figure 18. Example of storage dispatch in the SW region with weather data from 2000.

- Firm capacity:
  - Total of thermal capacity in the region, excluding any capacity already included in the CAISO Baseline.
  - No explicit modeling of forced outages, instead reduce nameplate capacity by a 7.4 percent weighted-average forced-outage rate. No ambient derate applied.

Regional Calibration

In some hours a region's generation capacity may not be sufficient to meet the managed load and operating reserves, leading to a residual supply of zero and positive unmet demand. CalCCA counted the number of days with an unmet demand across the 25 weather years to roughly estimate the LOLE in neighboring regions. Three of the regions (IID, LADWP, and SW) saw few unmet demand events leading to a LOLE less than 0.1 events/year. In these three regions we scaled down the firm capacity until the LOLE rose to 0.1 events/year. The calibration reduced firm capacity in these three regions by 15 to 19 percent.

In the two remaining regions, NCNC and NW, the LOLE was already above 0.1 events/year. In these regions we made no further changes to the firm capacity.

Unmet Demand

Hours where the region's calibrated supply was insufficient to meet managed load and operating reserves had unmet demand rather than residual supply. CalCCA represented unmet demand in PLEXOS as a load in the neighboring region with an hourly profile across the 25 weather years. Unmet demand could be met by imports from residual supply, subject to the transmission limits.

Residual Supply Relative to Energy Division's Simultaneous Import Limit

CalCCA used the residual supply, unmet demand, and transmission limits to illustrate how often available imports would be below Energy Division's SIL. Figure 19 shows that available imports almost always exceed the SIL, except for afternoon hours between June and September. In those hours, available imports can be below the SIL at most 5 percent of the time.

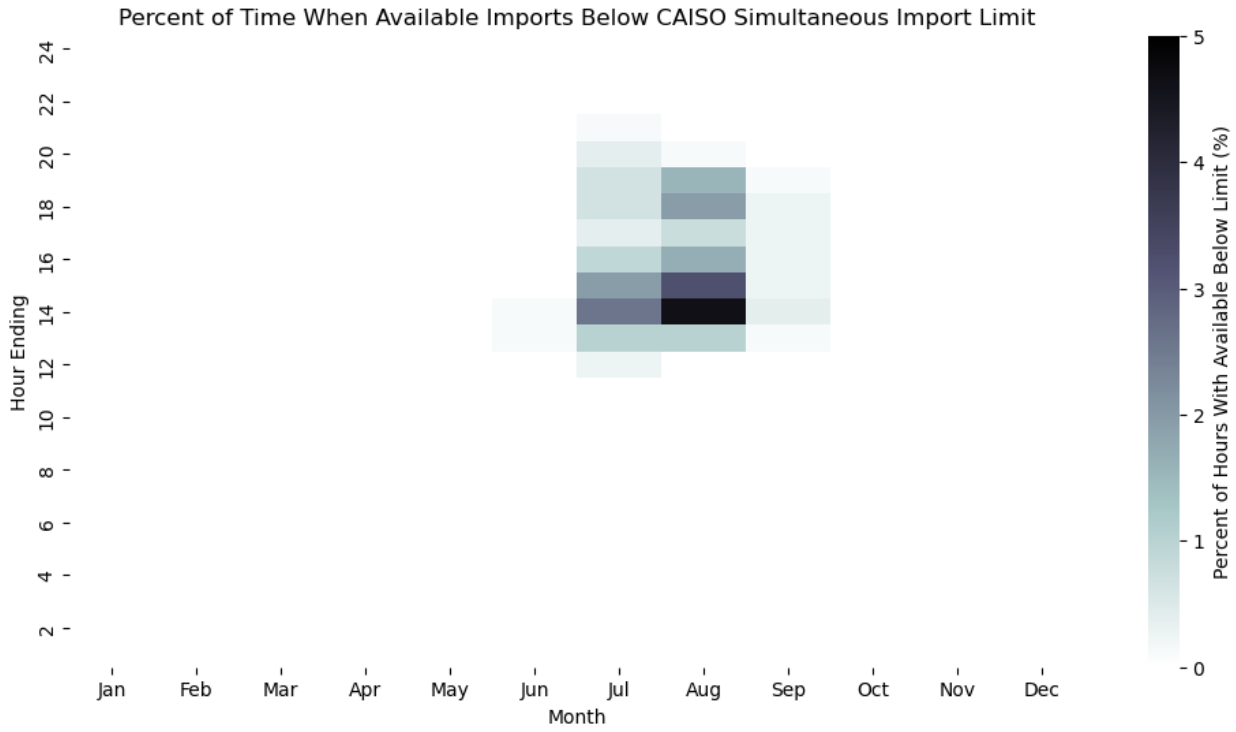


Figure 19. Percentage of hours with available imports less than Energy Division's SIL.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2027 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U 39 E)	A.26-05-007

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON PACIFIC GAS AND ELECTRIC COMPANY'S FALL UPDATE TESTIMONY

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November 4, 2026

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SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS[1]

- PG&E'sFall Update testimony undermines its critique of SCE's interim SoD RA valuation methodology (which CalCCA supports). Based on the Fall Update, the ratio of Retained Solar RA quantity produced by SCE's methodology per MW of peak hour NQC declines by 25% to 1.22. PG&E's "effective solar value" analysis is therefore misleading. The Commission should direct PG&E to apply SCE's interim SoD methodology across all resource types, including intermittent resources;

- The Commission should approve PG&E's proposal to use available [redacted] before applying [redacted] towards its Minimum Retained RPS requirement for the purpose of the 2027 ERRA Forecast proceeding, and should take up the question of REC loading order in the ongoing PCIA rulemaking;

- In light of CalCCA's AFR of D.26-09-047, the Commission should require PG&E to track any Pre-2019 Banked RECs it uses for bundled customer RPS compliance in 2026 and forward.

- The Commission should adopt the recommendations CalCCA made in its Opening Brief.

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

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 2027 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U 39 E)	A.26-05-007

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON PACIFIC GAS AND ELECTRIC COMPANY'S FALL UPDATE TESTIMONY

The California Community Choice Association [2] (CalCCA) hereby submits these Comments on Pacific Gas and Electric Company's (PG&E) Fall Update Testimony [3] in the *Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2027 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U 39 E)* (Application) [4] pursuant to the schedule adopted in the Assigned Commissioner's Scoping Memo and Ruling (Scoping Memo). [5] CalCCA is separately and

[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, 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, Valley Clean Energy, and WestLight Energy.

[3] Exhibit PG&E-5.

[4] Application (A.) 26-05-007, *Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2027 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U39E)* (May 15, 2026).

[5] A.26-05-007*, Assigned Commissioner's Scoping Memo and Ruling* at 5 (Aug. 3, 2026) (Scoping Memo).

simultaneously filing a Reply Brief in this proceeding consistent with the schedule adopted in the Scoping Memo.

The Power Charge Indifference Adjustment (PCIA) rates PG&E proposes have increased significantly since PG&E filed its Application and prepared testimony[6] in May and its errata testimony[7] in July. Whereas proposed 2027 system average PCIA rates for all vintages ranged between 0.7 and 1.6 cents per kilowatt-hour (kWh) in PG&E's July errata testimony, PG&E now proposes PCIA rates above 3 cents/kWh for almost all vintages, with rates for several vintages surpassing 4 cents.[8]

The Commission's updated Market Price Benchmarks (MPB), released on October 1, 2026, are the predominant drivers of those increases. The Renewables Portfolio Standard (RPS) MPB fell from $62.45/MWh (the Forecast 2026 RPS MPB used for ratesetting in PG&E's May and July testimony) to $30.88/MWh (Final 2026 RPS MPB), and falls even further to $12.69/MWh in 2027 (Forecast 2027 RPS MPB). These dramatic declines, combined with more modest declines in the Resource Adequacy (RA) and Energy MPBs, put upward pressure on PCIA rates. That is because for departed customers who pay the PCIA, PG&E must credit the value of its resources' attributes (i.e., RPS, RA and Energy attributes) against the costs departed customers owe to bundled customers. As such, when the value of the attributes associated with PG&E's PCIA portfolio *decreases*, the forecast PCIA revenue requirement and the Portfolio Allocation Balancing Account (PABA) true-up *increases*, resulting in departed customers paying higher PCIA rates.

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6 Exhibit PG&E-1.

7 Exhibit PG&E-2.

8 *See* Attachment B to PG&E's Fall Update Testimony, Table 13-3, presenting Proposed PCIA rates assuming the Commission approves interim rate recovery in PG&E's pending Phase 1 General Rate Case, A.25-05-009.

In this proceeding, CalCCA addresses several proposals that impact PG&E's PCIA rates, including PG&E's Retained RA methodology, its Retained RPS calculation, and its data center load and peak demand forecasts. The most significant dispute between CalCCA and PG&E concerns PG&E's approach to calculating the Retained RA quantity associated with non-storage intermittent resources—an important input to the broader PCIA revenue requirement calculation. PG&E's approach fails to reflect the Commission's transition to a Slice-of-Day (SoD) framework for RA compliance, and this flaw inflates PCIA rates in 2027. CalCCA recommends the Commission direct PG&E to implement Southern California Edison Company's (SCE) "interim SoD methodology" for calculating Retained RA across resource types as a reasonable interim solution.

PG&E's Fall Update testimony did not result in CalCCA modifying its recommendation, and on the contrary, undermines PG&E's chief opposition to SCE's methodology—namely, its impact on Retained Solar RA quantity. Based on PG&E's Fall Update, SCE's interim SoD methodology would produce only a modest increase in Retained Solar RA quantity relative to PG&E's approach, while producing a decrease in Retained Wind RA quantity relative to PG&E's approach. As discussed in detail below, these results demonstrate that PG&E overstates the impact of SCE's interim SoD methodology. The Commission should direct PG&E to implement SCE's SoD methodology as a reasonable interim solution until the Commission comprehensively addresses SoD implementation in the PCIA rulemaking (R.25-02-005).

These comments also briefly respond to the Fall Update's discussion of Decision (D.) 26-07-008 issued in the RA rulemaking, PG&E's Retained RPS calculation, PG&E's data center forecasts, and PG&E's General Rate Case (GRC) revenue requirement. Again, nothing in PG&E's Fall Update causes CalCCA to modify its Opening Brief recommendations. However, in light of

CalCCA's Application for Rehearing (AFR) of the Commission's Track Two Decision in the PCIA OIR (D.26-09-047), CalCCA recommends the Commission require PG&E to track any Pre-2019 Banked Renewable Energy Credits (REC) it uses for bundled customer RPS compliance in 2026 and forward. Further, the Commission should approve PG&E's proposal to use available [redacted] before applying [redacted] towards its Minimum Retained RPS requirement for the purpose of the 2027 ERRA Forecast proceeding and should take up the question of REC loading order in the ongoing PCIA rulemaking.

For the reasons described herein, CalCCA recommends that the Commission:

- Direct PG&E to apply SCE's interim SoD methodology across all resource types, including intermittent resources;
- Approve PG&E's proposal to use available [redacted] before applying [redacted] towards its Minimum Retained RPS requirement for the purpose of the 2027 ERRA Forecast proceeding, and should take up the question of REC loading order in the ongoing PCIA OIR;
- In light of CalCCA's AFR of D.26-09-047, require PG&E to track any Pre-2019 Banked RECs it uses for bundled customer RPS compliance in 2026 and forward; and
- Adopt CalCCA's Opening Brief recommendations.

I. PG&E SHOULD BE DIRECTED TO APPLY SCE'S INTERIM SOD METHODOLOGY ACROSS ALL RESOURCE TYPES, INCLUDING INTERMITTENT RESOURCES

PG&E's Fall Update continues to calculate the RA value of its intermittent resources based on each resource's peak hour contribution.[9] As CalCCA explained in its Opening Brief, PG&E's RA valuation methodology fails to reflect the Commission's transition to a SoD framework for RA program compliance, which shifts the focus of compliance away from the peak hour.[10] PG&E's RA valuation methodology is also misaligned with SCE's interim SoD methodology for

[9] Exhibit PG&E-5 at 12.
[10] CalCCA Opening Brief at 21-23.

all resource types, which the Commission has repeatedly approved as an interim solution until SoD implementation is addressed holistically in a rulemaking.[11] SCE's methodology—which CalCCA supports as an interim approach—calculates the RA value of intermittent resources based on the resource's average exceedance value across 24 hours.[12]

PG&E opposes SCE's methodology. Its chief criticism of that methodology is that it would allegedly "value solar RA at a premium."[13] In support of that assertion, PG&E conducted an analysis, premised on its assumption that SCE's methodology (as applied to PG&E's PCIA portfolio) would produce approximately 1.62 MW of retained solar quantity for each MW of peak-hour Net Qualifying Capacity (NQC). That calculated ratio is based on Table RAM-3 from CalCCA's direct testimony, which presents Retained RA Capacity quantities by resource-type under PG&E's methodology as well as SCE's interim SoD methodology.[14]

As CalCCA pointed out in its Opening Brief, however, this calculated ratio cannot bear the weight PG&E places on it. The results of SCE's interim SoD method depend on the average RA contribution of intermittent resources across the 24 hours of the "worst day" of each month. This means that methodology would not necessarily produce an increase in retained Solar RA capacity in every instance (relative to a peak-hour NQC-based method). In other words, the 1.62 MW of Solar RA / MW of peak-hour NQC ratio PG&E uses as the predicate for its analysis is simply a product of the application of SCE's methodology at a single point in time, not a defining feature of that methodology.

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11 *See id*. at 17-18, citing D.24-12-039 and D.25-12-028.
12 *Id*. at 17, citing Exhibit CalCCA-01C at 13; Attachment RAM-4.
13 PG&E Opening Brief at 23.
14 *See* Exhibit CalCCA-01 at 17.

Indeed, the same ratio declines significantly in PG&E's Fall Update. Based on PG&E's Fall Update, the Retained RA Capacity associated with each resource-type in PG&E's PCIA portfolio, under PG&E's SoD methodology and SCE's interim SoD methodology, is as follows:

Table 1: Updated Table RAM-3 based on PG&E's Fall Update (Retained RA Capacity by Resource-Type)

Capacity (MW)	**PG&E SoD Methodology**	**SCE Interim SoD Methodology**	**Difference**
Biomass	92	92	-
Digester Gas	2	2	(0)
Geothermal	18	18	(0)
Landfill Gas	22	22	0
Hydro	2,557	2,557	0
Fossil	1,703	1,703	-
Solar PV	672	821	149
Solar Thermal	144	177	33
Wind	191	167	(24)
Total	5,401	5,558	158

The ratio of Retained Solar RA produced by SCE's interim SoD methodology to the retained Solar RA produced by PG&E's methodology is now **1.22** ([821 MW solar PV + 177 MW solar thermal)/[672 MW solar PV + 144 MW solar thermal])—a 25 percent decline from the calculation presented in PG&E's rebuttal testimony. Thus, PG&E's claim that SCE's interim SoD methodology would effectively value PG&E's solar RA at $224.68/kW-year is misleading.

Ultimately, the Commission should approve a Retained RA valuation methodology in this proceeding that reflects the Commission's transition to a SoD framework, while recognizing that it will more comprehensively address SoD implementation in the PCIA rulemaking. The Commission has repeatedly recognized that SCE's interim SoD methodology strikes that balance. It should therefore direct PG&E to apply that methodology to its intermittent PCIA resources on an interim basis. CalCCA's Reply Brief, filed concurrently herewith, comprehensively responds to PG&E's defense of its flawed Retained RA valuation methodology.

II. PG&E SHOULD IMPLEMENT D.26-07-008'S DIRECTIVES RELATED TO RA VALUATION

As CalCCA explains in its Opening Brief, the Commission recently adopted reforms that better align RA capacity calculations with the real-world operational experience for three distinct kinds of resources: energy storage resources experiencing foldback; energy-only resources; and long-duration storage resources.[15] PG&E's Fall Update incorporates the directives from D.26-07-008 related to energy-only resources.

In response to CalCCA discovery, PG&E confirmed it has one energy-only solar resource paired with a battery. PG&E indicated that it incorrectly recorded that resource's RA value in PG&E's PCIA workpaper, and stated that it intends to correct the record of this proceeding to account for the error. CalCCA reserves its right to supplement these comments once PG&E corrects its error, and once CalCCA has evaluated the impacts of that correction.

PG&E further explains that reforms related to long-duration energy storage resources do not affect PG&E's 2027 Forecast because PG&E does not expect any non-pumped-storage long-duration energy storage resources to be operational in 2027.[16] Further, its Fall Update does not reflect the reforms related to energy storage resources experiencing foldback, because "the Master Resource Database modifications necessary to support those calculations have not yet been implemented."[17] CalCCA agrees PG&E should incorporate those reforms into its RA valuation methodology once it is practical to do so.

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15 CalCCA Opening Brief at 38.
16 Exhibit PG&E-5 at 12.
17 *Id*.

III. PG&E'S PROPOSAL TO RETAIN AND VALUE UNSOLD RPS VOLUMES SHOULD BE APPROVED, BUT THE COMMISSION SHOULD LIMIT PG&E'S ABILITY TO DISPLACE RECS APPLIED TOWARDS MINIMUM RETAINED RPS ENTRIES IN PRIOR YEARS

As it initially described in its rebuttal testimony, PG&E's Fall Update confirms it intends to apply Unsold REC volumes towards its Minimum Retained RPS requirements for [redacted] and will credit the underlying vintages for PG&E's use of those RECs at the applicable RPS MPB.[18] PG&E's updated [redacted] entries result in more banked RECs being available to meet its [redacted] minimum retained RPS requirement, and PG&E has therefore updated its [redacted] entries accordingly. **Confidential Table 2** below illustrates PG&E's updated proposal to meet its minimum retained RPS requirements in [redacted]

Confidential Table 2: PG&E's Net Short and Use of RECs to Meet its Minimum Retained RPS Shortfall

	May Filing			Fall Update		
Year	Net Short	Bank Volume	Bank Vintage	Net Short	Bank Volume	Bank Vintage
[redacted]						

CalCCA supports PG&E's use of Unsold RPS volumes towards its Minimum Retained RPS requirement and confirms that PG&E has appropriately valued RECs at the applicable year's RPS MPB, consistent with the requirements of D.19-10-001.[19] As PG&E explains, its approach will

[18] *Id*. at 13.

[19] CalCCA notes, however, that it has issued a discovery request (CalCCA to PG&E 16.01) regarding PG&E's accounting of RECs previously used towards Minimum Retained RPS compliance in 2026. A response to that discovery request remains pending at the time these comments were filed. CalCCA reserves its right to supplement these comments based on PG&E's response to that discovery request.

"keep [Unsold] RECs from expiring and reducing the amount of RECs available to PG&E and the broader market for use towards meeting future RPS compliance requirements."[20]

However, PG&E's approach raises certain discrete concerns. As **Confidential Table 2** illustrates, PG&E's approach displaces vintage [redacted] RECs previously applied towards PG&E's [redacted] Minimum Retained RPS requirements. While PG&E now applies certain vintage [redacted] and [redacted] RECs towards its [redacted] and [redacted] shortfalls, PG&E no longer applies any [redacted] RECs towards its [redacted] shortfalls.

As CalCCA explains in its Opening Brief, parties closely examine and routinely litigate PG&E's RPS accounting in ERRA Forecast and Compliance cases, including PG&E's Minimum Retained RPS entries.[21] This includes any banked RECs PG&E applies towards the Minimum Retained RPS requirement. PG&E and CalCCA already litigated PG&E's use of banked RECs towards its 2025 Minimum Retained RPS requirement, for example, in the 2024 and 2025 ERRA Forecast cases.[22] In each case, the Commission approved revenue requirements, including PCIA revenue requirements, that reflected the specific RECs PG&E proposed to use towards its Minimum Retained RPS requirement.[23] The Commission should therefore expressly limit PG&E's ability to displace the RECs it previously applied towards a prior year's Minimum Retained RPS requirement, and permit PG&E to make changes for [redacted] only to the extent it displaces previously-used banked RECs with expiring Unsold RPS volumes.

Finally, PG&E's Fall Update Testimony notes—and **Confidential Table 2** illustrates—that it will first use available [redacted] towards its minimum retained RPS shortfall

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20 Exhibit PG&E-4 at 4-3.
21 CalCCA Opening Brief at 32.
22 *Id*.
23 *Id*.

before meeting any remaining shortfall with [redacted]. While REC loading or usage order is a relevant issue for the existing PCIA rulemaking, in the meantime PG&E's proposal to use available [redacted] towards any shortfall before using [redacted] is a reasonable interim solution. The Commission should, however, require PG&E to track any Pre-2019 Banked RECs used for bundled customer RPS compliance in 2026 and forward. In Track 2 of the ongoing PCIA rulemaking, CalCCA argued that the investor-owned utilities should either: (a) value any Pre-2019 Banked RECs used for bundled customer RPS compliance at the compliance-year RPS MPB and credit that value to the customer vintage corresponding to the RECs' generation year; or (b) proportionately allocate those RECs to Later Departed Customers.[24] The Commission's D.26-09-047 in Track 2 of the PCIA OIR instead adopted a zero-dollar value in the PCIA for Pre-2019 Banked RECs used for bundled customer RPS compliance. CalCCA has filed an Application for Rehearing of that decision, explaining why that decision is erroneous and unlawful.[25]

Again, in PG&E's Fall Update, it forecasts applying [redacted] Minimum Retained RPS requirement. The Commission should require PG&E to track the use of any Pre-2019 Banked RECs, including the vintage from which they are drawn, to ensure that any later Commission or court decision requiring a non-zero value or allocation of the RECs can be easily implemented.

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[24] *See* R.25-02-005, *California Community Choice Association's Application for Rehearing of Decision 26-09-047* (Oct. 22, 2026) at 2-4.

[25] R.25-02-005, *California Community Choice Association's Application for Rehearing of Decision 26-09-047* (Oct. 22, 2026)

IV. THE COMMISSION SHOULD REVISIT THE LOAD FORECAST MEET AND CONFER PROCESS IN THE PCIA OIR

PG&E's Fall Update Testimony makes several updates to its data center forecasting methodology, including updates to capacity materialization, ramping and operating assumptions. These updates should improve the accuracy of PG&E's data center load forecast.

PG&E's Fall Update testimony also discusses the meet-and-confer process through which PG&E and community choice aggregators (CCAs) providing service in PG&E's territory develop load and peak demand forecasts. As CalCCA describes in its Testimony and Opening Brief, data centers introduce the potential for significant swings in that forecast and consequently create the risk of volatility in the PCIA. CalCCA therefore recommends that the Commission revisit the meet-and-confer process in the pending PCIA rulemaking because the current process does not contemplate rapid, large-load additions.

PG&E's Fall Update Testimony defends the existing meet-and-confer process, observing that in this cycle, it largely adopted the CCAs' forecasts. PG&E asserts it did not use the forecast of only one CCA, and that CCA "communicated no objection to PG&E using its internal forecast."[26] While any alignment between PG&E and CCAs in this cycle is encouraging, the Commission should nevertheless revisit the meet-and-confer process in the PCIA rulemaking. PG&E admits that in the event of misalignment between a CCA's load forecast and PG&E's load forecast, CCAs are not entitled to any recourse besides a good-faith continuation of discussions during the period between PG&E's Prepared Testimony and the Fall Update.[27] Even after a CCA explains its load forecasting models and assumptions, PG&E has no obligation to incorporate it. Had that CCA objected, it would have expended time and resources to negotiate an agreeable

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[26] Fall Update Testimony at 11.

[27] CalCCA Opening Brief at 36 (citing Exh. CalCCA-14).

forecast with PG&E without any assurance from PG&E or incentive for it to adopt the CCA's reasoning.[28] That lack of a formal resolution process is outdated, given the oversized impact that inaccuracies in data center load forecasting have on PCIA volatility.[29] While CalCCA acknowledges that PG&E incorporated the load forecasts from 10 of 12 CCAs in the current ERRA Forecasting proceeding, accelerating large load additions will likely magnify misalignment between PG&E's and CCAs' load and peak demand forecasts going forward.[30] CalCCA therefore continues to recommend that the Commission revisit the meet and confer process in Track 3 of the PCIA rulemaking..[31]

V. INTERIM GENERAL RATE CASE REVENUE REQUIREMENT

PG&E's Fall Update Testimony states that on September 23, 2026, the Commission issued a proposed decision in PG&E's Phase 1 General Rate Case (GRC), A.25-05-009. This proposed decision grants interim rate relief, which, if approved, will increase PG&E's generation-related revenue requirements by an incremental $146 million, impacting PCIA rates among other rates.[32] CalCCA agrees that PG&E should incorporate the electric generation portion of PG&E's interim authorized GRC revenue requirement into the 2027 rates authorized in this proceeding.

VI. CONCLUSION

CalCCA appreciates the Commission's consideration of these comments on PG&E's Fall Update Testimony and requests the Commission adopt CalCCA's recommendations. CalCCA expressly reserves the right to supplement these comments as needed to address PG&E's response

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28 *Id*. (stating that when CalCCA and PG&E cannot agree on load forecasting, PG&E will use its own forecast).
29 *Id*.
30 *See id*. at 34.
31 *See id*. at 37-38.
32 Exhibit PG&E-5 at 31.

to pending discovery and address PG&E's correction to the RA value associated with its energy-only resource (as discussed herein).

November 4, 2026

Respectfully submitted,



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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2027 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U 39 E)	A.26-05-007

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY BRIEF

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SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS[1]

The Commission should adopt the recommendations in CalCCA's Opening Brief and Comments on PG&E's Fall Update, including its recommendation that the Commission direct PG&E to adopt SCE's interim SoD method across all resource types until the Commission comprehensively addresses SoD implementation in the PCIA rulemaking.

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

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 2027 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U 39 E)	A.26-05-007

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY BRIEF

Pursuant to Rule 13.12 of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission) and the schedule adopted in the Assigned Commissioner's Scoping Memo and Ruling (Scoping Memo),[2] the California Community Choice Association[3] (CalCCA) hereby submits this Reply Brief regarding the *Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements And Rates Associated with its 2027 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U 39 E)* (Application).[4] CalCCA is separately and simultaneously filing its Comments on Pacific Gas and Electric

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[2] Application (A.) 26-05-007, *Assigned Commissioner's Scoping Memo and Ruling* at 5 (Aug. 3, 2026) (Scoping Memo).

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

[4] A.26-05-007*, Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2027 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U39E*) (May 15, 2026).

Company's (PG&E) Fall Update per the schedule adopted in the Scoping Memo. CalCCA's Comments comprehensively address several issues raised or updated in PG&E's Fall Update testimony, including its Retained Resource Adequacy (RA) calculation, implementation of Decision (D.) 26-07-008, Minimum Retained Renewables Portfolio Standard (RPS) entries and use of banked Renewable Energy Credits (REC), data center load forecasts, and its incorporation of its interim General Rate Case (GRC) revenue requirement. This Reply Brief focuses on the proceeding's most significant remaining disputed issue in this proceeding between PG&E and CalCCA: PG&E's calculation of Retained RA quantities associated with non-storage intermittent Power Charge Indifference Adjustment (PCIA) resources.

The Commission revised PG&E's approach to calculating the Retained RA quantity associated with energy storage resources in last year's ERRA Forecast case to reflect the Commission's transition to a "Slice-of-Day" (SoD) framework for RA compliance. The Commission "agree[d] with PG&E that the Commission's RA regulatory program has changed enough to warrant a response"[5] and directed PG&E to apply Southern California Edison Company's (SCE) interim SoD methodology to its storage resources.[6] The Commission did not, however, address non-storage resources in that decision. Therefore, PG&E's approach to calculating the Retained RA quantity associated with non-storage resources (and in particular, intermittent resources) has not changed to reflect the new RA compliance paradigm. By ensuring that PG&E's Retained RA quantity calculation, for the purposes of PCIA ratemaking, is more reflective of the Commission's new RA compliance paradigm, the Commission can better ensure that PG&E's PCIA rates are reasonable, consistent with Public Utilities Code § 451, and do not

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5 D.25-12-027 at 37.

6 *Id*. at 38.

result in cost shifts between bundled and unbundled customers, consistent with Public Utilities Code §§ 365.2 and 366.2.

In its Opening Brief, PG&E claims its existing RA valuation methodology for non-storage intermittent resources is "aligned with the Commission SoD framework because both measure and value RA capacity in the same manner."[7] This claim about its methodology—which focuses on the resource's peak-hour RA capacity contribution, not its contribution over 24 hours—is incorrect. The prior RA compliance paradigm required load-serving entities (LSE) to demonstrate compliance with RA requirements during the peak hour. However, the SoD framework requires LSEs to show sufficient capacity to meet 24 separate hourly requirements during the day of each month when it is most difficult to deliver reliable, clean power to serve baseload demand and peak load. PG&E's proposed approach to non-storage intermittent resources continues to assess the Retained RA quantity associated with its intermittent resources based on the resource's peak-hour contribution. While the peak hour certainly remains relevant under the SoD framework, PG&E's continued focus on its intermittent resources' peak hour contribution *to the exclusion of* those resources' RA contributions across all other hours of the day cannot be squared with the structure of the Commission's new RA compliance paradigm. SCE's method, while not perfect, is a reasonable interim approach to calculating Retained RA quantity in light of the SoD compliance framework. Indeed, the Commission has twice reached that conclusion and approved SCE's approach (in SCE's 2025 and 2026 ERRA Forecast cases). The Commission should similarly direct PG&E to apply SCE's interim SoD method across all resource types as an interim solution until the Commission more comprehensively addresses SoD implementation in the PCIA rulemaking (R.25-02-005).

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[7] PG&E Opening Brief at 21.

I. THE COMMISSION SHOULD DIRECT PG&E TO APPLY SCE'S INTERIM SOD METHODOLOGY TO CALCULATE RETAINED RA QUANTITY ACROSS RESOURCE TYPES

PG&E's Opening Brief levels a series of criticisms at SCE's interim SoD methodology for intermittent resources (and CalCCA's support for that methodology), even though SCE's methodology is nearly identical to the one PG&E originally proposed in its initial filing in the 2026 ERRA Forecast case.[8] PG&E's criticisms do not withstand scrutiny.

First, PG&E criticizes SCE's methodology for allegedly valuing solar resources at a premium, even though those resources trade at a discount in the market.[9] This argument is misleading.

PG&E's assertion that SCE's methodology values solar resources at a "premium" rests on a flawed analysis. That analysis begins by dividing the quantity of Retained Solar RA produced by SCE's methodology (numerator) by the peak-hour Net Qualifying Capacity (NQC) (denominator) for PG&E's solar resources. Based on the numbers in CalCCA witness Matley's direct testimony, that calculation produces a ratio of 1.62. PG&E simplistically multiplies the RA MPB by that ratio, and claims that SCE's methodology would "effectively value[] a MW of solar RA retained by PG&E at approximately $224.68/kW-year[.]"[10] But this analysis is deceptive because it assumes that SCE's methodology would *always* produce a Retained RA quantity 1.62 times as large as the NQC of those resources. As CalCCA explained in its Opening Brief, this is inaccurate. The results of SCE's interim SoD method depend on the average exceedance value of intermittent resources across the 24 hours of the "worst day" of each month, which means that methodology would not necessarily produce an increase in retained Solar RA capacity in every

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8 Exhibit CalCCA-01 at 17.
9 PG&E Opening Brief at 22-25.
10 *Id*. at 25.

instance (relative to a peak-hour NQC-based method). In other words, the 1.62 MW of Solar RA per MW of peak-hour NQC ratio PG&E uses as the predicate for its analysis is simply a product of the application of SCE's methodology to PG&E's solar resources at a single point in time, not a defining feature of that methodology. Indeed, in the context of wind resources, the application of SCE's methodology produces a smaller quantity of Retained RA relative to those resources' NQC. And in the context of solar resources, the same ratio declines significantly in PG&E's Fall Update. Based on PG&E's Fall Update, the Retained RA Capacity associated with each resource type in PG&E's PCIA portfolio, under PG&E's SoD methodology and SCE's interim SoD methodology, is as follows:

Table 1: Updated Table RAM-3 based on PG&E's Fall Update (Retained RA Capacity by Resource-Type)

Capacity (MW)	**PG&E SoD Methodology**	**SCE Interim SoD Methodology**	**Difference**
Biomass	92	92	-
Digester Gas	2	2	(0)
Geothermal	18	18	(0)
Landfill Gas	22	22	0
Hydro	2,557	2,557	0
Fossil	1,703	1,703	-
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Solar Thermal	144	177	33
Wind	191	167	(24)
Total	5,401	5,558	158

The ratio of Retained Solar RA produced by SCE's interim SoD methodology to the retained Solar RA produced by PG&E's methodology is now **1.22** ([821 MW solar PV + 177 MW solar thermal)/[672 MW solar PV + 144 MW solar thermal])—a 25% decline from the calculation presented in PG&E's rebuttal testimony. Thus, PG&E's analysis is misleading because it suggests that SCE's interim SoD methodology would always value PG&E's solar RA at $224.68/kW-year. More fundamentally, PG&E's argument suggests that any methodology producing a Retained

Solar RA quantity greater than a resource's NQC must be wrong and must shift costs to bundled customers. But PG&E does not offer any evidence to support that hollow conclusion for that assumption, nor does it explain why a resource's peak hour NQC must remain the ceiling on its Retained RA quantity in light of the Commission's transition to a framework that creates RA compliance obligations across 24 hours.

Second, PG&E claims that SCE's methodology values solar RA "in a manner inconsistent with PG&E's RA retention", arguing that SCE's methodology "does not reflect the variable nature of intermittent resources."[11] But this argument is unsupported. PG&E simply asserts that "*increasing* the amount of solar retained is illogical given the intermittent nature of the resource",[12] but never explains why that result is "illogical." While PG&E's argument on this point is not clear, it appears to believe that any methodology that would average the exceedance values of an intermittent resource across 24 hours "would wrongly treat solar like a baseload resource[.]"[13] But this is incorrect. A baseload resource receives a Retained RA quantity equivalent to its NQC (under both PG&E's and SCE's methodologies), which tends to be near nameplate capacity.[14] Calculating a 24-hour average of exceedance values for intermittent resources, on the other hand, would reflect those resources' variable RA contributions across 24 hours (consistent with the SoD framework). Unlike baseload resources, this would result in an RA quantity well below those resources' nameplate capacities.

Third, PG&E claims that SCE's methodology presumes the peak hour is no longer relevant to RA compliance.[15] This argument mischaracterizes SCE's methodology. While SCE's

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11 *Id*.
12 *Id*. at 26 (emphasis *sic*).
13 *Id*.
14 Exhibit CalCCA-01 at 16.
15 PG&E Opening Brief at 26.

methodology does not *focus* on peak-hour contributions in light of the RA program's transition towards contributions across 24 hours, it nevertheless captures intermittent resources' peak-hour RA contributions by averaging exceedance values across all 24 hours. Put simply, the methodology accounts not only for a solar resource's ability to supply RA during the peak hour but also for the same resource's output during all other hours of the day, because LSEs now have RA compliance obligations across all of those hours. PG&E points to solar resources' "minimal" peak hour contributions in the winter months to support its approach, but this, in fact, highlights a weakness in that approach. As CalCCA explained in its Opening Brief, the value of solar RA, under the SoD framework, would not be zero in winter months; rather, it would be driven by the resource's contribution across all 24 hours of the "worst day" in each winter month.[16] Thus, a methodology that focuses solely on a solar resource's peak-hour contribution would undervalue that resource in winter and fail to reflect changes in its value under a SoD framework.

Finally, PG&E leans on the PCIA rulemaking, arguing that a "potential statewide methodology for SoD . . . is in scope for Track 4 of R.25-02-005 and should be litigated in that proceeding."[17] PG&E also questions the need to align with SCE prior to the Commission's consideration of a statewide methodology, arguing "SCE could modify their interim methodology to match PG&E's approved interim SoD methodology to achieve a consistent outcome."[18] Relatedly, PG&E criticizes CalCCA for "propos[ing] to modify *one* element of the interim PG&E framework without addressing the broader valuation structure."[19] These arguments are unavailing. In last year's ERRA Forecast proceeding, the Commission directed a change to PG&E's Retained

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16 CalCCA Opening Brief at 27.
17 PG&E Opening Brief at 22.
18 *Id*.
19 *Id*. (emphasis *sic*).

RA quantity calculation for storage resources on an "interim basis", recognizing that the Commission would eventually address SoD implementation more comprehensively in the PCIA rulemaking. The Commission is yet to undertake that comprehensive review in the PCIA rulemaking, and so the rationale for adjusting PG&E's Retained RA quantity calculation to reflect the SoD framework remains just as strong this year as it was last year. CalCCA has consistently supported a holistic review of the impacts of SoD implementation on both price and quantity terms in the Retained RA calculation. But the price term is not subject to change in this proceeding, and therefore PG&E's criticism of CalCCA for proposing to only modify the quantity term for non-storage resources misses the mark. And while CalCCA supports alignment across the three investor-owned utilities with respect to the Retained RA calculation, the Commission need not wait until a rulemaking to promote alignment. In particular, the Commission has approved SCE's methodology on multiple occasions,[20] but has not yet addressed PG&E's Retained RA quantity calculation for non-storage resources.

The Commission should therefore direct PG&E to adopt SCE's interim SoD method for calculating Retained RA quantities, and in particular apply that method to its non-storage intermittent resources on an interim basis (until the Commission more comprehensively addresses SoD implementation in the PCIA rulemaking). The Commission can better ensure that PG&E's PCIA rates are reasonable — consistent with Public Utilities Code § 451 — and do not result in cost shifts between bundled and unbundled customers — consistent with Public Utilities Code §§

[20] *See* D.24-12-039, *Decision Approving Southern California Edison Company's 2025 Energy Resource Recovery Account-Related Forecast Revenue Requirement,* A.24-05-007 (Dec. 23, 2024), at 70; D.25-12-028, *Decision Approving Southern California Edison Company's 2026 Energy Resource Recovery Account-Related Forecast Revenue Requirements*, A.25-05-008 (Dec. 18, 2025), at 119.

365.2 and 366.2 — by ensuring that PG&E's Retained RA quantity calculation, for the purposes of PCIA ratemaking, is more reflective of the Commission's new RA compliance paradigm.

II. CONCLUSION

For the reasons described in its Briefs, Comments, and Testimony, CalCCA respectfully requests the Commission adopt the recommendations offered in CalCCA's Opening Brief and Comments on the Fall Update, including its recommendation that the Commission direct PG&E to adopt SCE's interim SoD method across all resource types until the Commission comprehensively addresses SoD implementation in the PCIA rulemaking.

November 4, 2026

Respectfully submitted,



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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 COMMENTS ON THE PROPOSED DECISION ADDRESSING DISCONNECTION CAPS, DISCONNECTION PILOTS, AND IDENTIFYING REMAINING ISSUES

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November 5, 2026

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SUMMARY OF RECOMMENDATIONS[1]

CalCCA recommends:

- Rejection of the increase to disconnection rate caps to prevent unnecessary harm to customers;
- Rejection of the proposal to require deposits for reestablishment of service for customers disconnected two or more times in the last 12 months;
- Establishment of AMP as a permanent program, with an income-based component, to ensure the continuation of support for customers in arrears, but rejection of the directive to create a post-enrollment verification process for AMP to limit administrative costs and given verification is already occurring through the CARE and FERA programs; and
- Adoption of the Proposed Decision's customer protections for current PIPP participants to prevent rate shock and customer confusion.

[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 COMMENTS ON THE PROPOSED DECISION ADDRESSING DISCONNECTION CAPS, DISCONNECTION PILOTS, AND IDENTIFYING REMAINING ISSUES

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 Addressing Disconnection Caps, Disconnection Pilots, and Identifying Remaining Issues*[4] (Proposed Decision), dated October 16, 2026.

I. INTRODUCTION

Decision (D.) 20-06-003 established residential disconnection rate caps and the Arrearage Management Program (AMP) pilot to limit disconnections and reduce statewide arrearages.[5]

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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, 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, Valley Clean Energy, and WestLight 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 Addressing Disconnection Caps, Disconnection Pilots, and Identifying Remaining Issues*, Rulemaking (R.) 18-07-005 (Oct. 16, 2026), https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=623836264.

[5] 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), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M340/K648/340648092.PDF.

Despite these efforts, customers continue struggling to remain current on their electric bills, and electric rates in California remain elevated. According to the latest monthly arrearage reports from investor-owned utilities (IOU), more than 2 million customers are in arrears, totaling more than $1.6 billion.[6] While these totals are on a slow decline since peaking during the COVID-19 pandemic, the magnitude of arrears still indicates a significant problem. The Proposed Decision is responsive to these issues, ensuring the continuation of much-needed customer support and protections to help customers pay their bills on time, reduce arrears, and prevent disconnections.

While CalCCA is supportive of the general direction of the Proposed Decision, modifications are necessary to minimize harm to customers and administrative burdens. *First,* the Proposed Decision's increase of disconnection rate caps over 2027 and 2028 should be rejected.[7] Increasing rate caps will cause unnecessary harm to customers already struggling to pay their bills without addressing the underlying cause of their struggle: high electricity rates.

Second, the Proposed Decision's creation of an exception to the general prohibition on deposits to reestablish service for customers who have been disconnected due to nonpayment two or more times within a 12-month period should be rejected.[8] The record does not support that subjecting these customers to higher reconnection costs through a deposit requirement would prevent their disconnection in the first place. This exception would also not address the high electricity rates that caused the nonpayment in the first place.

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[6] *See Pacific Gas and Electric Company's (U 39 M) Monthly Disconnect Data Report*, R.18-07-005 (Oct. 20, 2026), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M624/K559/624559272.PDF; *see also Southern California Edison Company's (U 338-E) Monthly Disconnect Data Report September 2026*, R.18-07-005 (Oct. 20, 2026), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M625/K126/625126276.PDF; *see also Disconnection Settlement Monthly Report of San Diego Gas & Electric Company (U 902 M)*, R.18-07-005 (Oct. 20, 2026), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M624/K559/624559274.PDF.

[7] Proposed Decision, Ordering Paragraphs (OP) 1 and 5.

[8] *Id.* at Conclusion of Law (COL) 11.

Third, CalCCA supports the Proposed Decision's establishment of a permanent AMP program with an income-based pilot component. This approach ensures the continuation of benefits from AMP while incorporating the recommendations for a combined bill assistance program and arrearage management assistance from the final evaluations for AMP and the Percentage of Income Payment Plan (PIPP) pilot.[9] However, the Proposed Decision's addition of post-enrollment verification should be rejected given the added administrative costs. In addition, this post-enrollment verification is unnecessary given AMP eligibility rules already require participation in either the California Alternative Rates for Energy (CARE) program or the Family Electric Rate Assistance (FERA) program, which themselves already have verification processes.

In addition to the above modifications, the Proposed Decision's adoption of customer protections for the soon-to-sunset PIPP pilot participants should be adopted to prevent unnecessary rate shocks and PIPP customer confusion. These customer protections include: (1) a 12-month glidepath to prevent bill spikes; (2) outreach to PIPP participants to ensure they understand the changes they will experience due to the PIPP sunset; (3) allowing PIPP participants to enroll in AMP; and (4) a temporary disconnection moratorium for PIPP participants.[10]

In summary, CalCCA recommends:

- Rejection of the increase to disconnection rate caps to prevent unnecessary harm to customers;
- Rejection of the proposal to require deposits for reestablishment of service for customers disconnected two or more times in the last 12 months;

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[9] *See Percentage of Income Payment Plan Pilot Program Final Evaluation Report* (PIPP Evaluation), R.18-07-005 (Mar. 17, 2025), at 79 (recommending consideration of a joint program that provides both energy bill payment assistance and arrearage forgiveness); *see also Arrearage Management Plan Final Evaluation Report* (AMP Evaluation), R.18-07-005 (Oct. 1, 2025), at 203 (stating that future assessment of program design should consider joint implementation of bill payment assistance (such as PIPP) and arrearage forgiveness programs).

[10] Proposed Decision, at 62-67.

- Establishment of AMP as a permanent program, with an income-based component, to ensure the continuation of support for customers in arrears, but rejection of the directive to create a post-enrollment verification process for AMP to limit administrative costs and given verification is already occurring through the CARE and FERA programs; and

- Adoption of the Proposed Decision's customer protections for current PIPP participants to prevent rate shock and customer confusion.

II. THE PROPOSED DECISION'S INCREASES TO DISCONNECTION RATE CAPS SHOULD BE REJECTED TO PREVENT UNNECESSARY HARM TO CUSTOMERS

While the Proposed Decision recognizes the importance of disconnection caps staying in place, the Proposed Decision's increases to disconnection rate caps should be rejected to prevent unnecessary harm to customers. The Proposed Decision accurately characterizes the challenge customers face in affording electric service but errs in increasing the IOUs' reliance on customer disconnections to incentivize timely payment of bills:

> [w]hile disconnection may incentivize some customers to prioritize payment of utility bills, **this approach does not account for the affordability challenges many customers face**. It also does not address the central purpose of this proceeding: developing alternatives to nonpayment that reduce reliance on disconnection.[11]

Simultaneously, the Proposed Decision contends that:

> [i]t is reasonable to allow a small increase in the allowable number of disconnections where such an increase could result in a significant decrease in arrearages. Therefore, we authorize a limited, conditional increase in disconnection caps.[12]

While the proposal to increase disconnection rate caps is designed to be modest (0.5 percent increase in 2027 and 0.5 percent increase in 2028) and accompanied by monitoring and safeguards,[13] it will still risk harming customers without addressing the underlying cause of

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11 *Id*. at 26 (emphasis added).
12 *Id*. at 20.
13 *Id.* at OP 1 and 5.

arrearages. Without reducing overall electric rates by addressing the list of growing utility costs, a disconnected customer will face the same challenges in affording service after reconnection. The Proposed Decision acknowledges and agrees with this concept, quoting CalCCA's own Opening Comments on the Assigned Commissioner's Ruling.[14] It goes on to require the IOUs to provide more detailed evidence on the relationship between increases to disconnection caps and arrearage reductions in lowering overall rates, acknowledging that the Commission does not have a full understanding of the benefits and harms of increasing disconnection rate caps.[15] Directing an action before having a full understanding of the impacts puts the cart before the horse. While CalCCA supports the IOUs providing more detailed evidence, increasing the disconnections rate caps without first analyzing that data is premature when the efficacy of increasing the caps is not yet supported by the record evidence.

The Proposed Decision explicitly states that the Commission is not persuaded to eliminate disconnection caps, despite the IOUs' argument that "increasing disconnections, or at least strengthening the threat of disconnection, is necessary to reduce arrearages."[16] IOU arguments on lifting or increasing disconnection caps rest on the premise that the majority, or a significant minority, of customers in arrears are somehow gaming the system to not pay their electric bills. No evidence to support this premise has been provided, however. In fact, the result could be that vulnerable customers are disconnected, potentially forcing difficult financial decisions and reprioritizing budgets to sacrifice other needs to reconnect service. While the

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[14] *Id.* at 31 (agreeing with CalCCA, the Utility Consumer's Action Network, The Public Advocates Office at the California Public Utilities Commission (Cal Advocates), the Center for Biological Diversity, and The Utility Reform Network, the Center for Accessible Technology, the National Consumer Law Center, and the Utility Consumers' Action Network (collectively, the Joint Consumer Advocates), the role of increased utility rates on customer arrearage levels).

[15] *Ibid*.

[16] *Id.* at 26.

Proposed Decision's disconnection cap increases seem modest at 0.5 percent, this translates to customers losing service in the name of gathering data to test the IOUs' hypothesis. The harm outweighs the benefits in this case. Therefore, the Commission should reject the Proposed Decision's increases to disconnection rate caps.

In the event that the Commission does adopt the Proposed Decision's disconnection rate cap increases, the Commission should require careful monitoring and workshops on monitoring and metrics as described in the Proposed Decision.[17]

III. THE PROPOSED DECISION'S REQUIREMENT OF DEPOSITS FOR REESTABLISHMENT OF SERVICE FOR CUSTOMERS DISCONNECTED TWO OR MORE TIMES IN THE LAST 12 MONTHS SHOULD BE REJECTED

The Proposed Decision's requirement of deposits for reestablishment of service for customers disconnected two or more times in the last 12 months should be rejected because it would cause unnecessary harm to vulnerable customers. In fact, the IOUs argue for reinstating deposit requirements for all customers because they are "effective tools to increase customer payments and elimination of deposits has increased arrearages and reduced on-time payment."[18] To the contrary, arrearages have likely increased due to rapid increases in electricity rates, not solely because the IOUs are prohibited from requiring reconnection deposits. While the Proposed Decision does acknowledge the harm that deposits generally cause to customers and maintains the general prohibition, its proposal to add an exception for customers who have been disconnected two or more times in the last 12 months should be rejected.[19]

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[17] *Id.* at 33-24 (adopting Cal Advocates' recommendation to require ongoing monitoring, the directive to require the IOUs to file and serve a formal Disconnection Cap Monitoring Strategy, and establishing workshops on the impacts of disconnection caps).

[18] *Id.* at 38.

[19] *Id.* at 40 (allowing the IOUs to require customers to pay a deposit for re-establishment of service if a customer has been disconnected for nonpayment two or more times in the prior 12 months).

In support of this proposal, the Proposed Decision states that "while the Commission lacked evidence in 2020 that elimination of deposits for all customers would increase arrearages, arrearages have increased significantly since the elimination of deposits."[20] While elimination of deposits may have contributed, this statement ignores the fact that electric rates have continued to rise since 2020 and have outpaced inflation since 2021.[21] The increased rates, along with other impacts in the economy, have likely intensified customer struggles to pay bills in full and on time. The goal described in the Proposed Decision is to control costs of "outlier customer behavior."[22] Yet there is no evidence in the record to suggest that outlier customer behavior is due to something other than high electricity rates. Additionally, there is no evidence as to how much this strategy will reduce overall arrearages, meaning there is no way to compare benefits to ratepayers with the harm caused to those who cannot afford the deposit to reconnect. Again, the Proposed Decision directs an action without having the information necessary to understand the impacts. Until further evidence is provided that the proposed exception to the prohibition on deposits has benefits that outweigh harms, the Commission should not adopt the Proposed Decision's establishment of deposits for certain customers.

IV. THE PROPOSED DECISION'S ESTABLISHMENT OF AMP AS A PERMANENT PROGRAM, WITH AN INCOME-BASED COMPONENT, SHOULD BE ADOPTED TO ENSURE THE CONTINUATION OF SUPPORT FOR CUSTOMERS IN ARREARS

The Commission should adopt the Proposed Decision's establishment of AMP as a permanent program with a pilot to test an income-based component to ensure continued support for customers in arrears. The AMP Evaluation demonstrated the success the pilot had in reducing

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20 *Id.* at 39.

21 *2026 Senate Bill 695 Report* (October 2026), at 3: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/office-of-governmental-affairs-division/reports/2026/2026-sb-695-report---final.pdf.

22 Proposed Decision, at 40.

customer arrearages,[23] which is acknowledged by the Proposed Decision.[24] Given the success of the pilot in helping customers make on-time payments and reduce arrears, it is reasonable to transition the pilot into a permanent program to continue supporting customers. As noted below, however, the Proposed Decision's adoption of a post-enrollment verification process should be rejected given that existing CARE and FERA verifications already exist.

A. The Proposed Decision's Directive to Develop An Income-Based Amp Pilot within the Permanent Amp Program Should Be Adopted

In addition to establishing a permanent version of AMP, the Proposed Decision also establishes an income-based AMP (IBAMP) pilot component to continue to test the benefits of capping bills for low-income customers and incorporate findings from the AMP and PIPP Evaluations.[25] The PIPP and AMP Evaluations recommend a program that provides both arrearage management and assistance with paying bills for low-income customers.[26] This addresses concerns raised in the PIPP Evaluation that the pilot did not meet its goal of controlling program costs[27] by developing a modified approach within the permanent AMP program. Incorporating recommendations from the PIPP Evaluation in developing IBAMP will allow the IOUs to revisit cost control measures while continuing to provide bill assistance for the most vulnerable customers. It will also allow the Commission to observe any synergies between providing arrearage management and bill assistance simultaneously to participants.

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23 AMP Evaluation, at Table ES-2, Row 1.

24 Proposed Decision, at 47 (stating AMP has demonstrated success at reducing arrearages and providing a path for customers to get current on utility payments).

25 *Id.* at 70.

26 PIPP Evaluation, at 79 (recommending consideration of a joint program that provides both energy bill payment assistance and arrearage forgiveness); AMP Evaluation, at 203 (stating that future assessment of program design should consider joint implementation of bill payment assistance (such as PIPP) and arrearage forgiveness programs).

27 PIPP Evaluation, at 69, Table IV-24, Row 4.

B. The Proposed Decision's Directive to Create a Post-Enrollment Verification Process for Amp Should Be Rejected to Limit Administrative Costs

The Commission should not adopt post-enrollment verification for the permanent AMP to limit administrative costs. The Proposed Decision states that, "AMP's benefits and associated costs for non-participants are high enough that eligibility verification is warranted."[28] This is despite the fact that customers participating in AMP have already been enrolled in CARE or FERA, which have their own eligibility checks. This would create a duplicative process that only stands to increase administrative costs, which the Proposed Decision already acknowledges are high. The Proposed Decision directs the IOUs to "take steps to reduce the administrative burden of their programs … with these additional verification steps."[29] However, there is no guarantee that this burden on both IOUs and customers can be reduced to an amount that justifies its costs, given that the process is redundant to the CARE and FERA verification processes. The concern that post-enrollment verification is needed stems from an IOU staff survey in the AMP Evaluation, which is anecdotal rather than quantitative.[30] Therefore, there is no quantitative evidence to suggest post-enrollment verification is necessary or worth the additional cost. The Commission should not adopt post-enrollment verification for the permanent AMP program.

V. THE PROPOSED DECISION'S CUSTOMER PROTECTIONS FOR CURRENT PIPP PARTICIPANTS SHOULD BE ADOPTED

The Proposed Decision's customer protections for customers currently enrolled in PIPP should be adopted to prevent spikes in customer bills, further deterioration of customers' financial situations, and customer confusion. The Proposed Decision adopts several protections for PIPP participants, including: (1) a 12-month glidepath to prevent bill spikes; (2) an outreach

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28 Proposed Decision, at 48.

29 *Id*.

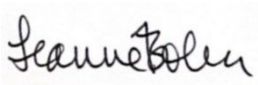
30 AMP Evaluation, at 11 (describing IOU staff recommendations to address concerns related to AMP eligibility).

program to PIPP participants to ensure they understand the changes they will experience due to the PIPP sunset; (3) allowing PIPP participants to enroll in AMP; and (4) a temporary disconnection moratorium for PIPP participants.[31] These protections provide reasonable timelines and safety nets to help PIPP participants adjust to no longer having an income-based bill. After all, participation in PIPP means a customer struggled to pay their bill and that they required assistance offered by the pilot. Ensuring these participants understand the changes they will see and the other options available to them (*e.g.*, participating in AMP if needed) is important to prevent further deterioration in their ability to afford electricity service.

VI. CONCLUSION

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

Respectfully submitted,



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November 5, 2026

[31] *Id.* at 62-67.

APPENDIX A
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION ADDRESSING DISCONNECTION CAPS, DISCONNECTION PILOTS, AND IDENTIFYING REMAINING ISSUES

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

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Proposed text additions show as **bold and underlined**

FINDINGS OF FACT

CONCLUSIONS OF LAW

~~**1. It is reasonable to increase disconnection rate caps for Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company by 0.5 percent.**~~

~~**2. It is reasonable to increase disconnection rate caps for Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company by an additional 0.5 percent based on results of an initial 0.5 percent increase.**~~

~~**11. It is reasonable to require the Large Utilities to each file and serve a Tier 2 Advice Letter to require deposits for reestablishment of service for customers that have been disconnected two times or more in the 12 months preceding the reestablishment of service.**~~

ORDERING PARAGRAPHS

~~**1. Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company are each authorized to increase their disconnections rate cap by 0.5 percent within 30 days of the compliance filing required by Ordering Paragraph 3.**~~

~~**5. Pacific Gas and Electric Company, Southern California Edison Company San Diego Gas & Electric Company are each authorized to increase their disconnection caps by an additional 0.5 percent above the amount authorized in Ordering Paragraph 1 12 months after the initial 0.5 percent increase authorized in Ordering Paragraph 1.**~~

New Order:

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Update Distribution Level Interconnection Rules and Regulations.	Rulemaking 25-08-004 (Filed August 14, 2025)

JOINT REPLY COMMENTS ON THE ADMINISTRATIVE LAW JUDGE'S PROPOSAL TO MODIFY TIMELINE REPORTING REQUIREMENTS AND APPLICATION FEES

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BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Update Distribution Level Interconnection Rules and Regulations.	Rulemaking 25-08-004 (Filed August 14, 2025)

JOINT REPLY COMMENTS ON THE ADMINISTRATIVE LAW JUDGE'S PROPOSAL TO MODIFY TIMELINE REPORTING REQUIREMENTS AND APPLICATION FEES

I. Introduction

Pursuant to the Administrative Law Judge's Ruling Seeking Comment on Proposal to Modify Timeline Reporting Requirements and Application Fees ("Ruling"), the Interstate Renewable Energy Council, Inc. ("IREC"), the California Solar & Storage Association ("CALSSA"), the Solar Energy Industries Association ("SEIA"), the California Community Choice Association ("CalCCA"), the California Energy Storage Alliance ("CESA"), and Pioneer Community Energy ("Pioneer") (collectively, "Joint Parties") submit these joint reply comments on the Ruling's timeline reporting proposal.[1]

Opening comments reflect broad consensus that the Commission should not pursue the Ruling's end-to-end framework. Parties, including the three utilities, broadly urged the Commission not to replace the existing step-level timelines with an end-to-end metric as the primary measure of utility performance. The utilities also answered the Ruling's specific questions about base timelines, adders, project groupings, and exemptions in some detail. The

[1] R.25-08-004, Administrative Law Judge's Ruling Seeking Comment on Proposal to Modify Timeline Reporting Requirements and Application Fees, at 1 (Oct. 8, 2026) (authorizing reply comments within one week of opening comments).

Joint Parties do not respond to those answers, as they concern the design of a framework the Joint Parties do not consider to be constructive for solving California's interconnection delays.

The utilities' comments are nonetheless revealing. While they oppose the end-to-end metric, the utilities largely support the Ruling's proposal to stop tracking key steps in the interconnection process, including steps governed by Rule 21 deadlines that Pacific Gas and Electric Company ("PG&E") and Southern California Edison Company ("SCE") routinely miss. That position confirms the central point of the Joint Parties' opening comments: the Commission must establish an enforcement and accountability framework, because the utilities do not treat their tariff deadlines as binding obligations. The Joint Parties also respond briefly to other issues raised in opening comments.

II. Parties Agree That the Commission Should Not Adopt the Proposed End-to-End Framework.

Parties generally urged the Commission not to adopt the end-to-end framework the Ruling proposes.[2] Indeed, party comments reflected an unusual consensus across utilities, advocates, developers, trade associations, and community choice aggregators, all broadly

[2] R.25-08-004, Joint Party Comments on the Administrative Law Judge's Proposal to Modify Timeline Reporting Requirements and Application Fees, at 1-3 (Oct. 29, 2026) ("Joint Party Comments"); R.25-08-004, Clean Coalition Comments on Administrative Law Judge's Ruling Seeking Comment on Proposal to Modify Timeline Reporting Requirements and Application Fees, at 1, 3-6 (Oct. 29, 2026) ("Clean Coalition Comments"); R.25-08-004, Tesla, Inc.'s Opening Comments on Administrative Law Judge's Ruling Seeking Comment on Proposal to Modify Timeline Reporting Requirements and Application Fees, at 11-12 (Oct. 29, 2026) ("Tesla Comments"); R.25-08-004, Opening Comments of Southern California Edison Company (U 338-E) on Assigned Commissioner's Scoping Memo and Ruling, at 1, 8 (Oct. 29, 2026) (responding to the Ruling) ("SCE Comments"); R.25-08-004, Pacific Gas and Electric Company's (U 39 E) Opening Comments on the Administrative Law Judge's Ruling Seeking Comment on Proposal to Modify Timeline Reporting Requirements and Application Fees, at 1-2 (Oct. 29, 2026) ("PG&E Comments"); R.25-08-004, Opening Comments of San Diego Gas & Electric Company (U 902-E) on Administrative Law Judge's Ruling Seeking Comment on Proposal to Modify Timeline Reporting Requirements and Application Fees, at 2, 5 (Oct. 29, 2026) ("SDG&E Comments").

opposed to shifting toward an end-to-end framework for similar reasons.[3] The Commission should recognize this as an opportunity to shift focus away from the Ruling's proposal.

Given party consensus, the Joint Parties do not respond to the utilities' suggestions on base timelines, adders, project groupings, treatment of repeated steps, or exemptions.[4] Those suggestions assume the Commission will adopt an end-to-end metric, and the Joint Parties disagree with that objective.

III. The Utilities' Support for Eliminating Tracking of Key Steps Confirms the Need for an Enforcement Framework.

Although the utilities do not support end-to-end measurement, each supports eliminating tracking of every timeline listed in Section 1.2.2 of the Ruling, including Acknowledgment of Receipt (Timeline A), the Electrical Independence Test (Timeline E), and the System Impact Study (Timeline H).[5] Those three timelines measure deadlines set in Rule 21, and the Commission applies its 95 percent compliance benchmark to them.[6] They are also deadlines PG&E and SCE regularly miss.[7]

The utilities offer little to justify removing these timelines. PG&E states that Timeline A is "administrative in nature and does not provide a meaningful standalone measure of utility

[3] PG&E makes a persuasive argument that end-to-end timelines are not desirable. PG&E Comments at 1-2 (stating that "PG&E is concerned that using an end-to-end timeline as the primary performance or compliance metric may combine numerous project-specific activities and dependencies that do not provide a consistent basis for comparing utility performance across projects"). The Joint Parties do, however, note PG&E's later argument that it "supports the Commission's proposal to evaluate interconnection performance primarily through an end-to-end timeline," which does not align with its earlier arguments. *Id.* at 15.

[4] *See, e.g.*, PG&E Comments at 7-9, 17-20; SDG&E Comments at 4-11.

[5] PG&E Comments at 5-6, 15; SCE Comments at 12; SDG&E Comments at 2.

[6] R.17-07-007, D.20-09-035, Decision Adopting Recommendations From Working Groups Two, Three, and Subgroup, Ordering Paragraph 28 (Sept. 24, 2020) ("D.20-09-035") (excluding from the benchmark only Timelines (f), (j), (l), and (s), "which are not stipulated in Rule 21"); *see* Joint Party Comments at 3.

[7] *See* Joint Party Comments at 12-13.

performance," and otherwise states that it favors removing the others.[8] SCE states that the removals are consistent with focusing reporting on "material, utility-controlled processing steps."[9] First, Electrical Independence Tests and System Impact Studies are critical evaluations the utility performs; they are material, utility-controlled steps by any measure. And while acknowledgment of receipt is a largely administrative step, it is still important for developers and a common, expected business practice that one would expect could be easily automated, which is why it is concerning that PG&E fails to perform the task on time.

The utilities' position on these timelines illustrates the central message of the Joint Parties' opening comments. The Commission mandated timeline reporting over six years ago. Utilities agreed to meet a 95 percent threshold for tariffed deadlines and were given time to report their progress without the concern of financial penalties. And now, PG&E and SCE are asking the Commission to stop measuring their compliance with deadlines in their own tariffs **for deadlines they routinely miss**. Rather than clearly articulate their intention to comply with the Commission's now-longstanding 95 percent threshold, the utilities deliver the clear message that they do not believe there should be any framework for accountability at all. The Joint Parties strongly encourage the Commission to take this opportunity to set interconnection processing on the right path by shifting toward a meaningful enforcement framework.

The utilities' opposition to most of the Ruling's proposed new timelines points in the same direction.[10] SCE objects that most of the proposed activities lack "established completion standards under Rule 21."[11] That is a reason to establish such standards, not to oppose reporting.

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[8] PG&E Comments at 5-6.

[9] SCE Comments at 12.

[10] PG&E Comments at 4-5; SCE Comments at 11-12; SDG&E Comments at 2-3.

[11] SCE Comments at 11.

As the Joint Parties recommended, where the Commission adds tracked steps it should add corresponding Rule 21 deadlines with defined start and stop points, so that each new timeline carries the same obligation as the existing ones.[12] The Commission should also return to the specific additional timelines parties proposed in scoping memo comments.[13]

IV. The Existing Step-Level Timelines Already Exclude Customer-Controlled Time.

The utilities recommend that step-level reporting be refined to separate utility-controlled time from time attributable to customers and third parties.[14] PG&E, for example, asks that reporting "distinguish periods attributable to utility processing from periods associated with applicant actions," and SCE asks that customer-response periods be identified separately.[15] The implication is that the current timelines mingle utility and customer time, and yet again, Joint Parties underscore that the existing timelines do not have that issue. Each existing timeline runs between defined events, and the clock starts only after the customer has completed its part.[16] No utility identifies an existing timeline that counts customer time against it. The utilities' examples of customer-dependent time concern proposed new timelines, such as site visits, inspections, and equipment Type Testing.[17] The Joint Parties agree that these timelines, like the existing timelines, should isolate utility action.

V. Other Issues

Two other proposals in opening comments warrant a brief response.

- *The Commission should not end SDG&E's timeline reporting.* SDG&E asks to be relieved of "recurring mandatory timeline reporting" because it has consistently met the

[12] Joint Party Comments at 13.

[13] *Id.* at 13 & n.39, 42.

[14] PG&E Comments at 1-2, 20; SCE Comments at 10; SDG&E Comments at 2, 11-12.

[15] PG&E Comments at 20; SCE Comments at 10.

[16] Joint Party Comments at 6, 8-9.

[17] PG&E Comments at 4-5; SDG&E Comments at 3.

95 percent benchmark.[18] The Joint Parties agree that SDG&E's record is strong, but do not support ending SDG&E reporting, which is the only way the Commission can reliably know whether SDG&E continues to meet its tariff obligations.

- *The Commission should not exclude projects of 30 kW or less from reporting.* PG&E argues that projects under 30 kVA should not be included in compliance reporting and states that it does not currently report on projects under 30 kW.[19] But only NEM projects under 30 kW are currently excluded.[20] PG&E's public reporting indicates that it does, in fact, report non-NEM projects under 30 kW, but Joint Parties raise this point to ensure the utilities' existing reporting obligations are clear. Smaller non-NEM projects, including standalone storage, non-export, and bidirectional EV systems, are a large and growing share of the non-NEM queue, and it is important the Commission track them and ultimately enforce an accountability framework that includes these projects.

VI. Conclusion

The Joint Parties respectfully request that the Commission decline to adopt the proposed end-to-end framework and the proposed removal of existing timelines; retain step-level timeline tracking for all three utilities; add the timelines in Section 1.2.1 and the additional timelines parties have proposed, with corresponding Rule 21 deadlines; and proceed to develop an enforcement framework built on the existing timelines.

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[18] SDG&E Comments at 1-2, 11-12.

[19] PG&E Comments at 6-7, 17.

[20] *Id.* (quoting D.20-09-035, Findings of Fact 145-146).