DECEMBER FILINGS

California Community Choice Association

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

1. Please provide your organization's questions or comments on the Modifications to TPD Allocations by these sections:

a. Allocation Groups b. Multi-fuel projects receiving an allocation with PPAs c. Opportunities to seek TPD i. In addition, the ISO seeks stakeholder input on whether a project should be able to seek an allocation during the interconnection facilities study by demonstrating they have a PPA. d. Eligibility of Energy Only projects, including technology additions i. The ISO seeks stakeholder input on whether pre-cluster 15 EO projects should be able seek TPD through the Commercial Operation group after the 2025 TPD allocation cycle. e. Modifications to the TPD scoring criteria

The California Community Choice Association (CalCCA) appreciates the opportunity to provide comments on the California Independent System Operator's (CAISO) Track 3 Revised Straw Proposal. The transmission plan deliverability (TPD) allocation process is a critical part of project development because resources must obtain TPD to provide resource adequacy (RA). The CAISO proposes to redefine the TPD allocation groups as: (1) the power purchase agreement (PPA) group; (2) the commercial operation group; and (3) the conditional allocation group. The CAISO's proposal would provide projects with three consecutive opportunities to seek a TPD allocation or retain a conditional TPD allocation, noting opportunities to seek and retain allocations of TPD are typically done on an annual basis but could be more than one year apart.[1]

CalCCA is still developing a position on this proposal and seeks clarification on the timing of the three opportunities to seek a TPD allocation for projects with and without conditional deliverability allocations after the first opportunity. The proposal states:

> *the first opportunity will be in the TPD allocation request window following the interconnection customer's receipt of its interconnection facilities study report. After the third opportunity to seek an allocation, projects that have not received an allocation will be withdrawn. Projects that do receive an allocation through the Conditional group, but are unable to retain their allocation in the next request window by demonstrating an eligible PPA will be withdrawn.**[2]***

Applying the proposal to the Cluster 15 study timeline[3] appears to result in the following timeline:

- Facilities Study Report: November 2026
- Beginning of first opportunity / TPD Affidavits: March 2027
- For projects with conditional deliverability after first opportunity:
  - Deadline to show a PPA or withdraw: March 2028[4]
- For projects without conditional deliverability after first opportunity:
  - Beginning of second opportunity / TPD Affidavits: March 2028
- For projects with conditional deliverability after second opportunity:
  - Deadline to show a PPA or withdraw: March 2029
- For projects without conditional deliverability after second opportunity:
  - Beginning of third opportunity / TPD Affidavits: March 2029

Therefore, projects appear to have roughly one and half years after receiving the facilities study report to demonstrate a PPA or be withdrawn if a project receives a conditional deliverability allocation. If a project does not receive a conditional deliverability allocation, it will also have until March 2028 to either sign a PPA to get into the PPA group or seek conditional deliverability for its second opportunity. **In the next iteration of the proposal, the CAISO should confirm or correct this understanding with a timeline or flow chart for the three opportunities using the Cluster 15 schedule, including the steps for projects that do and do not receive conditional allocations.** This clarification will help stakeholders develop positions on the proposal.

CalCCA appreciates the CAISO's responsiveness to stakeholder feedback in revising the PPA status points allocation criteria in Table 2 of the Straw Proposal. Categorizing projects based upon whether its PPA is with an off taker that has a RA obligation will result in a meaningful differentiation of projects that meet versus exceed the minimum requirement, because it bases its ranking on RA obligations which drive the need for TPD. It will also provide for uniform treatment of all PPAs with load-serving entities.

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[1] *See* Straw Proposal at 19.

[2] *Ibid.*

[3] https://www.caiso.com/documents/resource-interconnection-standards-interconnection-study-timeline.xlsx.

[4] For this example, assume one year between successive opportunities to seek and retain an allocation of TPD for simplicity, although they may be more than one year apart in practice.

2. Please provide your organization’s questions or comments on Special Considerations for Long Lead Time, Location Constrained Resources, specifically:

a. Eligibility b. Extension to seek TPD c. Broader procedural changes to the interconnection process for long lead-time, location-constrained resources

CalCCA agrees with the CAISO that it will be necessary to allocate TPD to long-lead time (LLT) resources such as offshore wind, out-of-state wind, and geothermal that currently have longer project development cycles that may not be compatible with the updated TPD allocation process outlined in Section 2. The CAISO’s straw proposal for allowing eligible resources an extension to seek TPD allocations can efficiently and equitably meet this need with additional work to define the details around: (1) how much TPD can be reserved for this purpose; and (2) when TPD that is reserved for LLT resources would be released after a certain time if it goes unused.

The straw proposal recognizes the need to release reserved TPD after a certain time, stating:

> The ISO will have to establish a deadline for specified projects to begin seeking TPD for each cluster, which should align with the timeframe for the resource coming online in portfolios. The ISO will also have to develop conditions or a trigger mechanism for releasing reserved TPD if generation or transmission does not materialize. Such conditions would need to be driven by the transmission planning process, such as changes to the policy scenarios or canceling transmission projects.[1]

As the CAISO further defines this process, it should avoid over-reserving for LLT, or maintaining reservations for projects that prove unviable, as TPD is “inherently finite.”[2] The process for allocating TPD to LLT resources should maintain the incentive for resources to seek a PPA as soon as practical so that LLT resources with reserved TPD do not retain it without a viable path to using it. The process for LLT resources with reserved TPD should maintain a clear deadline for projects without a PPA to be removed from the queue and the TPD released to make room for other projects to seek an allocation.

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[1] Straw Proposal at 32-33.

[2] Straw Proposal at 25.

3. Please provide your organization’s questions or comments on Intra-cluster Prioritization of Use of Existing SCD/RNU Headroom:

CalCCA supports the CAISO’s proposal to allow generators to interconnect up to an amount that will not trigger the need for the LLT short circuit upgrade or other reliability network upgrades. This proposal will provide opportunities for projects to come online and obtain deliverability more quickly when there is headroom to do so, helping to alleviate the current crisis of interconnection capacity scarcity.

4. Please provide your organization’s questions or comments on Modifications to the Priority for Awarding Interim Deliverability:

CalCCA has no comments at this time.

5. Please provide any additional feedback:

CalCCA has no comments at this time.

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

Application of Pacific Gas and Electric Company to Recover in Customer Rates the Costs to Support Extended Operation of Diablo Canyon Power Plant from September 1, 2023 through December 31, 2025 and for Approval of Planned Expenditure of 2025 Volumetric Performance Fees U 39 E	Application 24-03-018

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

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

CALIFORNIA COMMUNITY CHOICE
ASSOCIATION
1121 L Street, Suite 400
Sacramento, CA 95814
Telephone (415) 302-2376
E-mail: regulatory@cal-cca.org

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

Counsel to
CALIFORNIA COMMUNITY CHOICE
ASSOCIATION

Dated: December 4, 2024

SUBJECT MATTER INDEX

TABLE OF AUTHORITIES

Cases

Statutes

Commission Decisions

Rule 14.3 of the Rules of Practice and Procedure of the California Public Utilities Commission

SUMMARY OF RECOMMENDATIONS

- Apart from the issues identified herein, CalCCA[1] supports the ALJ's Proposed Decision, and recommends its adoption.

- The Proposed Decision rightly directs PG&E to value substitution capacity from its PCIA portfolio at the RA MPB; however, it should delete the provision in COL 13 requiring PG&E to apply an RA MPB mitigation measure from PG&E's ERRA Forecast in this proceeding. No changes to the RA MPB will result from that proceeding based on a recently published Proposed Decision, meaning the question is moot. What the ERRA PD does adopt cannot be implemented via a Tier 1 Advice Letter, is unreasonable for the DC NBC and its related balancing accounts and is not in scope in this proceeding.

- PG&E should not be required to file a Tier 3 Advice Letter to update its allocation of RA and GHG-free energy attributes because the utility will already file a Tier 2 advice letter to allocate those attributes. The utility has already made similar calculations in previous advice letter filings complying with D.23-12-036, meaning, at the very least, the Tier 3 requirement should be revised to a Tier 1 requirement.

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[1] Acronyms and defined terms used in the 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 to Recover in Customer Rates the Costs to Support Extended Operation of Diablo Canyon Power Plant from September 1, 2023 through December 31, 2025 and for Approval of Planned Expenditure of 2025 Volumetric Performance Fees U 39 E	Application 24-03-018

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
COMMENTS ON PROPOSED DECISION

The California Community Choice Association[2] (CalCCA) submits these Comments on Administrative Law Judge Atamturk's *[Proposed] Decision on Pacific Gas and Electric Company's (PG&E) Revenue Requirement to Support Extended Operation of Diablo Canyon Power Plant and 2025 Volumetric Performance Fees Proposal* (PD or Proposed Decision) pursuant to Rule 14.3 of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission).[3]

CalCCA supports much of the Proposed Decision, including its rejection of PG&E's proposal to modify the benefit allocation methodologies established in Decision (D.) 23-12-036. Further, CalCCA does not oppose the Commission's rejection of PG&E's spending plan for 2025,

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

[3] Application (A.) 24-03-018, *[Proposed] Decision on Pacific Gas and Electric Company's (PG&E) Revenue Requirement to Support Extended Operation of Diablo Canyon Power Plant and 2025 Volumetric Performance Fees Proposal* (Nov. 14, 2024) (Proposed Decision).

though the Proposed Decision's delay in establishing the guardrails CalCCA and other parties proposed for the use of revenues from volumetric performance fees—including prohibiting expenditures on hydroelectric generation infrastructure—is disappointing.

The Proposed Decision errs, however, in its resolution of the question of how to value substitution capacity needed when Diablo Canyon Power Plant (DCPP) goes on a planned outage. The PD rightly recognizes the Resource Adequacy (RA) Market Price Benchmark (MPB) is the correct measure of that value, but it should not act on PG&E's faulty suggestion to implement a mitigation measure regarding the RA MPB in a future Tier 1 advice letter filing for at least four reasons. First, the Proposed Decision published on November 25, 2024, in PG&E's ERRA Forecast case (ERRA PD) does not make changes to the RA MPB and rejects the mitigation measure PG&E's Fall Update references, meaning adoption of the ERRA PD would render Conclusion of Law (COL) 13 moot. Instead, the ERRA PD defers consideration of changes to the RA MPB to a future proceeding. Even if such an action could be called a mitigation measure, it could not be implemented in the manner PG&E contemplated (and the PD proposes), *i.e.*, "via a Tier 1 advice letter" and "in the next consolidated electric rate change filing with the Commission."[4] The legal and policy implications of retroactively modifying the calculation of the RA MPB true-up are unreasonable for consideration in a Tier 1 advice letter and should be considered in a full Commission proceeding where complex legal and policy questions can be resolved.

Second, the PD frames the mitigation measure as necessary to prevent under or over-collections in the ERRA balancing account, but that balancing account is irrelevant to the cost of substitution capacity from PG&E's Power Charge Indifference Adjustment (PCIA)-eligible

[4] Proposed Decision at 32, Conclusion of Law (COL) 13.

portfolio. It is the Portfolio Allocation Balancing Account (PABA) and the Diablo Canyon Extended Operations Balancing Account (DCEOBA) that matter when recording the transfer payment necessary to reflect the costs and value of substitution capacity.

Third, the impacts of the RA MPB are muted in this case and do not pit bundled customers against unbundled customers. Energy Division's November 5, 2024, revision to the RA MPB already reduces the substitution capacity cost estimate PG&E provided in the Fall Update by $11.4 million. The remaining costs are spread among all Commission-jurisdictional customers, meaning the change in the value of the RA MPB between PG&E's prepared testimony and its Fall Update (revised to include the updated RA MPB) is only seven-hundredths of a cent, or $0.0007/kWh. That impact also is only short-term since the forecasted RA MPB will be trued up against the final RA MPB in rates for 2026.

If the Commission finds the current methodology to calculate the RA MPB creates a cost shift in another proceeding, that cost shift in this case would be between *all Commission-jurisdictional customers* (all of whom pay the Diablo Canyon Nonbypassable Charge (DC NBC)) and *all customers in PG&E's service territory* (all of whom pay the PCIA) because PG&E must credit the PCIA and debit the DCNBC at the RA MPB for the substitution capacity it uses from its PCIA-eligible portfolio. It would not pit bundled customers against unbundled customers in PG&E's service territory. These legal and factual circumstances are far different than those presented in PG&E's ERRA Forecast case and weigh heavily against the need for a mitigation measure.

Fourth, neither changes to the RA MPB calculation methodology nor any mitigation measure are in scope in this proceeding. That means neither have been sufficiently examined by parties in testimony, hearing, briefs, or comments, and neither are supported by substantial evidence.

All of this is not to say the Commission should ignore the RA MPB if it feels that the current PCIA ratemaking methodology does not accurately reflect the market value of the utilities' capacity portfolios. As the ERRA PD appears to imply, if the Commission wishes to revisit how the RA MPB is calculated, it should follow the existing blueprint for doing so: (1) implement the existing framework for 2025; and (2) investigate the need for changes to the RA MPB—including those that may increase the value of the utility's portfolios—in a different proceeding with all parties, better resources, and more time.

Finally, the body of the PD requires PG&E to file a Tier 3 Advice Letter to align its calculation of the allocation of DCPP's RA capacity and greenhouse gas (GHG)-free energy with D.23-12-036. Ordering Paragraph (OP) 4, however, then requires a Tier 2 Advice Letter to allocate those attributes. It is unclear what additional purpose the Tier 3 advice letter in the body of the PD would serve and, therefore, it should be deleted. Alternatively, in light of Energy Division's disposition of PG&E Advice Letter 7295-E/E-A, PG&E should be required to file a Tier 1 Advice Letter instead of a Tier 3 Advice Letter.

I. THE PROPOSED DECISION ERRS IN ADOPTING AN RA MPB MITIGATION MEASURE

The PD errs in adopting the following mandate in COL 13:

> *13. If the Commission adopts measures to mitigate excessive over- or undercollections in the ERRA balancing account, PG&E should incorporate those measures into the DC NBC via a Tier 1 advice letter and implement those changes in the next consolidated electric rate change filing with the Commission.* [5]

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5 *Id.*

The PD's mandate arises in the context of PG&E's need to procure substitution capacity to replace DCPP when the facility is on planned outage in 2025.[6] PG&E has a choice to procure such capacity in the market or to use resources from its existing portfolio to provide the capacity. This issue only implicates the RA MPB—which is the subject of COL 13—if PG&E opts to use a PCIA-eligible resource from its existing portfolio as the substitution capacity. It is important to keep in mind that if PG&E uses a PCIA-eligible resource, the RA MPB does not set the level of a payment to PG&E or another generator. Instead, it is merely the value of a transfer payment between PG&E's own subaccounts, and the resulting transfer in cost responsibility between the two groups of customers responsible for paying those subaccounts.

PG&E's Fall Update provided the suggestion the PD adopts in COL 13, expressly tying that suggestion to an October 8 email ruling in the ERRA Forecast case requesting comments on procedural matters related to the updated RA MPB (October 8 Ruling), "and any changes resulting from that proceeding."[7] However, Judge Fox did not consider PG&E's proposal in response to the October 8 Ruling in reaching the ERRA PD because PG&E's proposals already had been ruled out of scope. That means: no changes to the RA MPB will result from that proceeding; no other party put a proposal forward regarding "procedural mechanisms"; and what the ERRA PD does adopt cannot be implemented via a Tier 1 Advice Letter, is unreasonable for the DC NBC and its related balancing accounts, and is not in scope in this proceeding. Therefore, the mandate in COL 13 should be deleted in the Final Decision.

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6 *Id.* at 28-33.

7 Exh. PG&E-08 at 20:5-26; A.24-05-009, *Email Ruling Requesting Party Comments on Procedural Mechanisms*, p. 3 (Oct. 8, 2024) (October 8 Ruling).

A. The ERRA Forecast Proposed Decision Would Render COL 13 Moot.

The Commission published the ERRA PD on November 25, 2024, rejecting a mitigation proposal PG&E had put forward twice in that proceeding. Instead, it stated "the Commission may in another proceeding consider revisions to the MPB methodology that may impact the adopted 2025 Final MPBs."[8] If the ERRA PD is voted out in its current form, the Commission would reject the only mitigation measure parties had proposed on the record in that case, and there would be no changes to the RA MPB "resulting from that proceeding,"[9] rendering COL 13 moot.

As the ERRA PD notes, PG&E had asked the Commission to consider a proposal to place a cap on the RA MPBs in its ERRA Forecast application and testimony on May 15, 2024.[10] The Commission concluded the proposal was beyond the scope of that proceeding in the scoping ruling in that case.[11] The October 8 Ruling reinforced the limited scope of that proceeding: it expressly affirmed the question of "whether the MPB methodology should be changed" remains firmly "outside of the scope" of the ERRA Forecast case.[12] In response to the October 8 Ruling, PG&E requested a Commission order directing parties "to brief the issue of whether the Commission should mitigate the impact of the escalated MPBs pending an evaluation of the calculation methodology in a future rulemaking[.]"[13] The Commission declined to issue the Order PG&E requested, remaining silent on the issue. Despite these repeated refusals, PG&E's Fall Update

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8 A.24-05-009, *[Proposed] Decision Approving Pacific Gas And Electric Company's 2025 Energy Resource Recovery Account Related Forecast Revenue Requirement And 2025 Electric Sales Forecast*, pp. 10, 21-22 (Nov. 25, 2024) (ERRA PD).

9 Exh. PG&E-08 at 20:5-26.

10 ERRA PD at 9-10.

11 *Id.* at 9-10; A.24-05-009, *Assigned Commissioner's Scoping Memo and Ruling*, p. 3 (Aug. 1, 2024).

12 October 8 Ruling at 3.

13 A.24-05-009, *Pacific Gas and Electric Company's (U 39 E) Response to Administrative Law Judge's Email Ruling Regarding Procedural Mechanisms*, p. 6 (Oct. 14, 2024).

Testimony in the ERRA Forecast proceeding asked the Commission to "mitigate" the impact of the Commission's MPBs by placing a cap on one or more of those MPBs, including the RA MPB.[14] Parties filed a Motion to Strike the portions of PG&E's testimony containing the "mitigation proposal" because the Commission had already ruled it out of scope.[15]

The ERRA PD resolves these issues by stating the Motions to Strike are moot "since the Commission did not consider this matter or related testimony in scope."[16] No party other than PG&E put forward a mitigation proposal in response to the October 8 Ruling. Thus, it does not appear as though the Commission will adopt a mitigation measure in the ERRA Forecast case if it votes out the ERRA PD in its current form. Instead, the ERRA PD would leave the issue for future resolution in a different proceeding. Conclusion of Law 13 in the PD should be deleted because no change to the RA MPB will be adopted in the ERRA PD, and, if that PD is approved, COL 13 is moot.

To the extent PG&E might argue the sentence in the ERRA PD amounts to a mitigation measure in the Commission's view, it cannot be implemented "via a Tier 1 advice letter…in the next consolidated electric rate change filing with the Commission,"[17] and COL 13 should still be deleted. Retroactive application of a modified benchmark to rates that are already in place carries with it significant legal and policy implications that are unreasonable for resolution via a Tier 1 Advice Letter.[18] Instead, the question of implementing retroactive modification of the 2025 Final

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14 A.24-05-009, Exh. PG&E-4, Attachment C.

15 A.24-05-009, *California Community Choice Association and Direct Access Customer Coalition's Joint Motion to Strike Portions of Pacific Gas and Electric Company's Fall Update Testimony* (Oct. 31, 2024).

16 ERRA PD at 10.

17 Proposed Decision at 32, COL 13.

18 *See* Cal. Pub. Util. Code § 454; General Order 96-B at Energy Industry Rule 5.1(3).

MPB should be an issue for consideration in a full Commission proceeding, *i.e.*, “another proceeding,” as referenced in the ERRA PD, or in next year’s iteration of the instant Diablo Forecast proceeding.

B. The ERRA Balancing Account is Largely Irrelevant to Extended Operation of DCPP.

A key factual shortcoming in requiring PG&E to incorporate into the DC NBC “measures to mitigate excessive over- or under-collections in the ERRA balancing account” is the PD’s reliance on the potential for under- or over-collections in the ERRA balancing account. PG&E records the at-market cost of its PCIA-eligible generation portfolio to the ERRA balancing account and recovers those costs via its bundled customers’ generation rates. However, as of the date extended operations began, November 1, 2024, the ERRA balancing account no longer includes DCPP costs because those costs are now recorded to the DCEOBA and recovered via the DC NBC.

If PG&E uses a PCIA-eligible resource from its existing portfolio as the substitution capacity, the utility will transfer the market value of the capacity between two balancing accounts. The market value of replacement capacity will be charged to the DCEOBA (not ERRA) and recovered through the DC NBC (not PG&E’s bundled customer generation rates). An offsetting credit equal to the value of the replacement capacity will be recorded to PABA (not ERRA) and recovered via PCIA rates (not bundled customer generation rates).

The PD’s requirement to include RA MPB mitigation measures is therefore based on a clear error in fact. The “excessive over- or under-collections” the PD references as allegedly tied to the RA MPB have nothing to do with the ERRA balancing account. There is no justification for adopting mitigation measures tied to the ERRA in this proceeding because the ERRA balancing account is largely irrelevant to DCPP’s extended operations.

C. No Rate Impacts or Bundled Versus Unbundled Customer Conflict Warrant Adopting Mitigation Measures.

The stakes of any "excessive over- or under-collections" are much lower than the PD suggests and will not be shouldered solely by PG&E's bundled customers but shared broadly by all Commission-jurisdictional customers *after* they are trued up for accuracy with the Final RA MPB. In fact, the amounts at issue have already decreased. Energy Division issued a revised RA MPB on November 5 that reduced the 2025 Forecast System RA MPB from $42.54/kW-month to $40.31/kW-month.[19] The revisions also changed the 2024 Final System RA MPB from $28.65/kW-month to $26.26/kW-mo.[20] Those reductions are minor, but they do lower the forecasted cost of substitution capacity by $11.4 million, from the $210.1 million figure cited in the PD to $198.7 million, if PG&E opts to use a PCIA-eligible resource from its portfolio to provide substitution capacity.

Also, the potential per-customer impact is small because the costs are spread over multiple service territories. If the ultimate cost of substitution capacity is lower than the cost forecasted in this case, it will be trued up, with the difference making its way into rates for 2026. For example, PG&E used the forecasted 2024 RA MPB in its prepared testimony, leading to the $78 million estimate of substitution costs the PD cites as the original estimated substitution cost, *i.e.*, the estimate prior to the Fall Update.[21] If the 2024 Forecast RA MPB turns out to be a perfect estimate of the cost of replacement capacity from PG&E's portfolio in 2025, *i.e.*, the final benchmark is the same as 2024 forecasted benchmark, there would be a $120 million overcollection ($198 million minus $78 million). As noted above, that over-collection would be recorded to DCEOBA and not

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19 Market Price Benchmark Calculations 2024 (Nov. 5, 2024).

20 *Id.*

21 Proposed Decision at 30. PG&E asked the Commission in its ERRA Forecast proceeding to simply use the forecasted 2024 RA MPB instead of the forecasted 2025 RA MPB to set rates in that case.

to ERRA. Since *all Commission-jurisdictional customers* pay the charges stemming from DCOEBA via the DC NBC, *all customers* would split that over-collection. Dividing $120 million over that many customers substantially dilutes its impact. The amount at stake here—the amount that would be subject to this mitigation measure—is a meager *seven-hundredths of a cent* per kWh ($0.0007/kWh).

On the other side of the coin, all PG&E customers pay the charges or enjoy the credits stemming from the PABA via the PCIA, meaning both bundled and unbundled customers would share the costs or benefits from a true up. While state law requires the Commission to set rates ensuring indifference between bundled and unbundled customers,[22] the Commission has more flexibility in setting rates here. If the Commission finds, in another proceeding, that the current methodology to calculate the RA MPB creates a cost shift, the cost shift here would be between *all Commission-jurisdictional customers* (all of whom pay the Diablo Canyon Nonbypassable Charge (DC NBC)) and *all customers in PG&E's service territory* (all of whom pay the PCIA).

Thus, not only is the potential rate impact small between forecasted and final rates, the potential shift in cost responsibility is not between bundled and unbundled customers in PG&E's service territory but rather between all customers in the state and all customers in PG&E's service territory. These well-diluted potential rate impacts outweigh the administrative headaches, policy shortcomings and legal risk that adoption of the mitigation measure in the PD represents.

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22 *See, e.g.,* Cal. Pub. Util. Code § 366.2(g).

D. The Proposed Decision Commits Legal Error by Relying on the Record in Another Proceeding.

The Scoping Ruling categorized this proceeding as ratesetting.[23] The Commission has previously determined that Section 1757 of the Public Utilities Code applies to ratesetting,[24] 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." That means they must be based on the record or inferences reasonably drawn from the record.[25]

As a result, the Commission cannot grant any relief in this proceeding without substantial evidence to support that relief.[26] California courts will overturn Commission decisions that lack substantial evidence.[27] Mere rubber-stamping of uncorroborated, disputed evidence does not meet this standard.[28] The Commission, therefore, must reject the adoption of any mitigation measure in this proceeding if it is not supported by substantial evidence.

No substantial evidence exists to support the mitigation measure. The lack of evidence stems from the fact that modifications to the RA MPB—whether as part of the Final Decision in this proceeding or as part of any advice letter process ordered in that Final Decision—are not in

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23 A.24-03-018, *Assigned Commissioner's Scoping Memo and Ruling*, p. 6 (June 18, 2024) (Scoping Memo).

24 Cal. Pub. Util. Code § 1757; *see, e.g.,* D.20-05-027 at 5-6 (stating "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.").

25 *See, e.g., id.* at 6.

26 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).

27 *Id*.

28 *Id*.

scope in this case.[29] While TURN and PG&E have referenced concerns raised in other proceedings, they have provided no record evidence substantiating those concerns in this case.[30]

Highlighting how far out of bounds the mitigation measure is in this PD are the differences between the process and stakeholder input in the ERRA forecast case versus this case. In this case, unlike the ERRA Forecast case, there has been no extraordinary ALJ Ruling like the October 8 Ruling, no proposed mitigation measures, no substantive proposals on how to revise the benchmark calculations, and no legal briefing or discussion on whether retroactive application of new methodologies is appropriate. There simply is no record on which the Commission can require PG&E to incorporate mitigation measures into its next consolidated rate change.

II. PG&E SHOULD NOT BE REQUIRED TO FILE A TIER 3 ADVICE LETTER TO CORRECT ITS ATTRIBUTE ALLOCATION CALCULATIONS

The PD rightly denies PG&E's proposal to modify the methodology adopted in D.23-12-036 for allocating RA attributes and GHG-free energy attributes. However, in two places in the body of the PD, it requires PG&E to "follow the direction provided in D.23-12-036, update its calculations, and submit a Tier 3 Advice Letter showing compliance within 30 days of the issuance of this decision."[31] Ordering Paragraph 4 then requires a Tier 2 Advice Letter in order to allocate those attributes: "Pacific Gas and Electric Company must submit a Tier 2 Advice Letter to allocate resource adequacy and greenhouse gas-free energy attributes as directed by Decision 23-12-036."[32] The Commission should either delete the Tier 3 requirement in the body of the PD or modify it to be a Tier 1 Advice Letter.

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29 *See* Scoping Ruling at 3-4.

30 A.24-03-018, *Opening Comments of The Utility Reform Network to Update Prepared Testimony*, pp. 2-4 (Oct. 18, 2024); Exh. PG&E-8 at 20:5-26.

31 Proposed Decision at 51; 55-56.

32 *Id.* at OP 4.

PG&E has already completed the calculations for 2025 the Commission would require be presented in a Tier 3 Advice Letter. PG&E presented a methodology compliant with D.23-12-036 in Advice Letters 7295-E and 7295-E-A, of which Energy Division disposed of on October 16, 2024, effective September 29, 2024. That advice letter was a Tier 2 advice letter, similar to the one required by D.23-12-036. It is unclear what additional purpose the Tier 3 advice letter in the body of the PD would serve and, therefore, it could be deleted.

Alternatively, should the Commission determine the advice letter is still necessary in addition to the Tier 2 advice letter in OP 4, modifying the requirement to be a Tier 1 will reduce administrative burden, including the need for the full Commission to vote on resolution of the Advice Letter and make it available for comment via a Draft Resolution.[33] Under General Order 96-B, a Tier 1 advice letter is appropriate for actions such as calculating a change in a rate or charge pursuant to an index or formula, as long as the rate or change is not being calculated for the first time.[34] That situation is analogous to that presented in the PD. Decision 23-12-036 lays out the formula PG&E must follow to allocate RA and GHG-free benefits, the utility has already presented a correct methodology for doing so, and Energy Division has already approved PG&E's methodology. Little, if anything, would need to change with regard to that calculation on account of the Commission adopting the PD.

III. CONCLUSION

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

33 *See* General Order 96-B at Rule 7.3.5, Energy Industry Rule 5.3.

34 General Order 96-B at Energy Industry Rule 5.1(3).

Respectfully submitted,

/s/Tim Lindl

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

Counsel to
CALIFORNIA COMMUNITY CHOICE ASSOCIATION

Dated: December 4, 2024

Appendix A

CalCCA's Recommended Changes to Conclusions of Law

Pursuant to Rule 14.3(b) of the Commission's Rules of Practice and Procedure, CalCCA offers the following index of recommended changes to the Proposed Decision, including proposed additions to the Proposed Decision's Conclusions of Law. CalCCA's proposed revisions appear in underline and strike-through.

Conclusions of Law

~~13. If the Commission adopts measures to mitigate excessive over- or undercollections in the ERRA balancing account, PG&E should incorporate those measures into the DC NBC via a Tier 1 advice letter and implement those changes in the next consolidated electric rate change filing with the Commission.~~

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENTS REGARDING FUTURE GRID STUDY REPORT

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

CALIFORNIA COMMUNITY CHOICE
ASSOCIATION
1121 L Street, Suite 400
Sacramento, CA 95814
Telephone: (415) 302-2376
E-mail: regulatory@cal-cca.org

December 6, 2024

TABLE OF CONTENTS

SUMMARY OF RECOMMENDATIONS

CalCCA provides the following recommendations in response to the FGS Report:

- Open access to the distribution grid should be the highest priority operational need;
- Dispatchability/control must apply not only to IOUs, but also to non-IOU LSEs and third-party DER providers;
- CAISO visibility into DERs should be a near term priority to unlock the full economic value of DERs, and to ensure accurate load forecasting and reliable grid planning;
- Stakeholder recommendations that ease grid constraints, reduce energization timelines, minimize grid upgrades, and reduce costs should be prioritized; and
- The FGS Report should be modified to accurately reflect the Joint CCAs' workshop comments.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENTS REGARDING FUTURE GRID STUDY REPORT

California Community Choice Association[1] (CalCCA) submits these comments pursuant to the *Administrative Law Judge's Ruling Seeking Comments Regarding Future Grid Study Report*[2] (Ruling)*,* dated October 17, 2024. The Ruling seeks comments on the Future Grid Study (FGS) Report, including responses to specific questions posed in the Ruling.

I. INTRODUCTION

CalCCA appreciates the opportunity to comment on the FGS Workshop Series (the Workshops) and FGS Report. Community choice aggregators (CCAs), serving more than 14 million customers across California, play a vital role in the evolution of the grid to support a high distributed energy resources (DERs) future. DERs provide benefits to CCA customers, such as minimizing

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

2 *Administrative Law Judge's Ruling Seeking Comments Regarding Future Grid Study Report*, Rulemaking (R.) 21-06-017 (Oct. 17 2024): https://docs.cpuc.ca.gov/SearchRes.aspx?docformat=ALL&docid=543421872.

resource adequacy (RA) costs, lowering customer bills, reducing greenhouse gas (GHG) emissions, and contributing to grid reliability. As noted in the Ruling, "diverging approaches" to operational characteristics of a high DER future were identified during the Workshops.[3] Data sharing and transparency in DER interconnection were also identified as "friction points."[4]

Before answering the Ruling questions, CalCCA provides general comments and recommendations in response to the FGS Report regarding CCAs and a high DER future. *First,*

the FGS Report presents two operational pathways for reaching a high DER future grid: (1) an investor-owned utility (IOU) top-down grid orchestration path; and (2) an open-access, bottom-up path. As set forth herein, the open-access path should be prioritized as it provides the greatest opportunity for CCAs to support a high DER grid while preserving CCAs' ability to manage costs and meet community goals.

Achieving this goal requires access to accurate and timely grid and customer load data needed to unlock DERs' full potential, thereby maximizing the value of these resources to support the transition to a high DER future. The California Public Utilities Commission (Commission) should prioritize data sharing, transparency, and accessibility to economic signals to ensure full and fair participation of DER.

Second, the Commission should ensure DER dispatchability and control applies to not only IOUs, but also non-IOU load serving entities (LSE) and third-party DER providers. This will enable non-IOU controlled DER to work in lockstep with IOU-controlled DER to maximize grid benefits.

Third, ensuring DER visibility to the California Independent System Operator (CAISO) is a critical near-term operational need to unlock the full economic value of DERs and enhance their ability to provide grid resiliency.

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3 Ruling, at 4.

4 *Ibid.*

Fourth, the Commission should prioritize stakeholder recommendations that reduce energization delays and minimize the need to upgrade the distribution grid. In particular, the Commission should pursue solutions that leverage DERs to maximize available capacity on the existing grid and offset costly grid upgrades.

Fifth, while the FGS Report includes many of the Joint CCAs'[5] workshop comments, the Report should be amended to incorporate omitted comments regarding the lack of sufficient information on distribution system needs and aligned economic incentives for CCAs to develop new programs or optimize existing ones according to local system needs.

In addition to answers provided to the Ruling questions below, CalCCA provides the following recommendations:

- Open access to the distribution grid should be the highest priority operational need;
- Dispatchability/control must apply not only to IOUs, but also to non-IOU LSEs and third-party DER providers;
- CAISO visibility into DERs should be a near term priority to unlock the full economic value of DERs, and to ensure accurate load forecasting and reliable grid planning;
- Stakeholder recommendations that ease grid constraints, reduce energization timelines, minimize grid upgrades, and reduce costs should be prioritized; and
- The FGS Report should be modified to accurately reflect the Joint CCAs' workshop comments.

II. OPEN ACCESS TO THE DISTRIBUTION GRID SHOULD BE THE HIGHEST PRIORITY OPERATIONAL NEED

In response to the Ruling question regarding the prioritization of identified operational needs, the highest priority operational need for CCAs is an open-access distribution grid. The top-down, grid orchestration approach favored by the IOUs perpetuates IOU market control, potentially

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[5] Joint CCAs include Ava Community Energy, Peninsula Clean Energy, San Diego Community Power, San José Clean Energy, Silicon Valley Clean Energy, and Sonoma Clean Power. These CCAs are all members of CalCCA.

limiting the pool of available DERs to support grid operations and offset grid investments. The top-down approach also risks devaluing non-IOU-controlled DERs. An open-access grid will enable all DER owners/operators to provide grid support and to have a stake in preparing the grid for a high DER future.

Establishing an open-access distribution grid will require all DERs to have access to data on current and forecasted grid conditions, customer loads, DER locations, and DER operational characteristics. During Workshop 1, the Utility Consumers' Action Network (UCAN) proposed a statewide data hub for third parties to access customer and operational data and a statewide data registry containing DER data.[6] The proposed data hub would provide two-way access to data necessary for optimizing DER, regardless of who owns or controls it. However, establishing a statewide data hub could take years and be a long-term goal.

A statewide DER registry would house DER technical specifications and capabilities' data and be accessible to IOUs, non-IOU LSEs, the CAISO, and regulators. This DER data can support grid planning and reliability, DER deployment and optimization, and may help reduce energization delays on circuits needing capacity upgrades. Several FGS Workshop participants support modeling a DER registry after the Commission's Distributed Generation Statistics (DG Stats) platform.[7] Modeling the DER registry after DG Stats may make it easier and quicker to establish and should be pursued as a near-term objective.

Data alone does not ensure DERs will operate in a manner that supports grid needs. Just as the CAISO does for wholesale market participants, IOUs acting as Distribution System Operators

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6 UCAN Workshop Presentation, *R.21-06-017, Track 2: Future Grid Workshop #1, Operational Needs for California's High DER Future* (Feb. 8, 2024), slides 3-10: https://gridworks.org/wp-content/uploads/2024/02/UCAN_Future-Grid-Workshop-1-Feb.-8-2024-public-final.pdf.

7 *See* FGS Report, at 45, 50: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M543/K418/543418944.PDF.

(DSOs) must also provide economic signals and compensation for verified responses. DERs enrolled in an LSE program or tariff have little ability to provide grid support services without these signals and compensation. LSEs like CCAs have strong incentives to run DER programs *to benefit customers* because they were established to serve local customer needs. However, CCAs do not currently have adequate access to signals and compensation to run their DER programs *to the benefit of the distribution grid.* Establishing the right signals can allow existing and future DER programs to be leveraged to meet both needs.

The ultimate objective of any open-access model should be animating DER marketplaces. A DER marketplace can be the most logical and efficient means of conveying economic signals, providing needed transparency, verifying performance, and compensating DER owners/operators. An independent marketplace operator can register and qualify marketplace participants, facilitate bidding and dispatch of resources, verify performance, and conduct settlement functions. Such a system can simplify transactions between the DSO and DER providers, enabling the participation of a greater volume of DER response than the proposed top-down grid orchestration model. The marketplace can eventually expand to provide access to the CAISO's wholesale markets, further supporting a high DER future and creating additional potential value for DER owners/operators.

For all the reasons set forth above, the Commission should establish open access to the distribution system as the highest priority operational need.

III. DER DISPATCHABILITY/CONTROL MUST APPLY TO NON-IOU LSES AND THIRD-PARTY PROVIDERS AS WELL AS IOUS

DER dispatchability/control is a near-term priority, but it must not be limited to IOUs, as implied in the grid orchestration framework. Under an open-access distribution grid, all DERs should be able to support the efficient, cost-effective operation of a high DER grid, regardless of who owns or operates them. Providing non-IOU LSEs and third-party DER providers with the appropriate data and economic signals enables them to operate their DERs to support grid needs, as discussed in section II above.

IOUs have a significant role in a high DER future, but in an open-access system, they do not need exclusive visibility and control of all DERs on the distribution grid. IOUs should instead focus on developing Advanced Distribution Management Systems (ADMS) and other tools to allow themselves, non-IOU LSEs, and third-party DER providers to monitor and respond to rapidly changing demands on the distribution grid. IOUs should be required to provide access to data, signals to non-IOU LSEs and third-party DER providers, and monetary compensation for supporting grid operations and offsetting grid investments. Such a system will not preclude IOUs from deploying Distributed Energy Resources Management Systems (DERMS) to dispatch DERs owned by their customers, under contract with an aggregator, or IOU-owned assets.

Several CCAs have deployed, or are considering deploying, DERMS to monitor and dispatch customer owned DERs.[8] Even though these resources are not integrated with an IOU ADMS/DERMS, CCAs can still dispatch them to support grid needs if the appropriate signals and compensation are provided. The IOU ADMS/DERMS can provide a direct economic signal to the CCA-owned DERMS, which in turn can dispatch its own DERs in accordance with its established parameters.

The above example is not the only means for a non-IOU LSE to control DERs. Non-IOU LSEs can also contract with third-party aggregators or demand response providers. DERMS are sophisticated systems that require significant cost and effort to set up and maintain and may not be the best or most cost-effective solution for all LSEs. Whether a non-IOU LSE chooses to use a

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

DERMS or a lower-cost alternative, it should be able to control its own resources directly and have access to the necessary data, signal, and compensation.

In all events, non-IOU LSEs and third-party DER providers should be able to support the efficient, cost-effective operation of a high DER grid through DER dispatchability/control in an open-access system.

IV. CAISO VISIBILITY INTO DERS SHOULD BE A NEAR-TERM PRIORITY TO UNLOCK THE FULL ECONOMIC VALUE OF DERS AND TO ENSURE ACCURATE LOAD FORECASTING AND RELIABLE GRID PLANNING

Ensuring the appropriate level of DER visibility to the CAISO is a critical near-term operational need to unlock the full economic value of DERs and enhance their ability to provide grid resiliency. As reflected in the FGS Report, the CAISO has access to data on behind-the-meter solar but lacks data on other types of DERs.[9] The CAISO requires visibility into load drivers and DERs to ensure reliability of the wholesale markets.[10] This visibility is essential for improving the CAISO's operational forecasts, real-time assessments, situational awareness, contingency planning, and market design efforts.[11] As more DERs are integrated into the grid, the need for the CAISO to have visibility into these resources becomes more critical to ensure accurate load forecasting and reliable grid planning.

Importantly, the CAISO visibility of DERs could result in more DERs participating in the wholesale markets, creating additional value for DER owners and operators. CCAs are particularly concerned about their ability to manage RA costs and see the additional value DERs could provide for RA as an opportunity that has yet to be fully leveraged. Many CCA DER programs are designed to reduce peak loads but do not receive RA credit for the reductions. Instead, they can reduce future

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9 *See* FGS Report, at 45, 53.
10 *Id.*, at 25, 65.
11 *Id.*, at 25.

RA obligations if they can justify load reductions resulting from these programs as load modifiers in the California Energy Commission's (CEC) load forecast process.

Alternatively, for DERs to be counted as RA resources, there must be certainty that they are available to meet reliability needs. Currently, to provide that certainty, resources must be integrated into the CAISO markets and have must-offer obligations to ensure they can be dispatched to meet grid needs under current rules. The CAISO also requires visibility to individual DERs, which must interconnect through the Wholesale Distribution Access Tariff (WDAT) for a CCA to receive RA credit from its DER programs. Doing so is often cost-prohibitive for DERs.

Establishing DER marketplaces that enable wholesale market participation may provide an alternative to the current structure for participation in the CAISO markets. This may offer a lower cost of entry into the wholesale markets. Still, it is uncertain if CCAs would receive RA credit for resources bid into these DER marketplaces or whether the CAISO would still require WDAT interconnection and visibility to individual DERs. The DER marketplace would appear as a large aggregation in the wholesale markets, and rules would need to be developed to assign RA credit to individual DERs or aggregators. The CAISO must still be certain these resources will show up before allowing them to count as RA.

The layered system architecture approach proposed by 350 Bay Area in Workshop 1 is another potential alternative.[12] Under this framework, demand is met first at the load level, leveraging DERs to meet the demand. Each layer of the grid has a point of interconnection with the next layer up, eventually reaching the transmission grid. Resources are managed within each layer, and the operator responsible for each layer does not need visibility for the layers below it. The

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[12] *See* 350 Bay Area Workshop Presentation – *High-DER Grid Modernization Workshop #1: Identifying Operational Needs, Panel 3* (Feb. 8, 2024): https://gridworks.org/wp-content/uploads/2024/02/350BA-HighDER-Workshop-1-2.8.24-Final.pdf.

CAISO would, therefore, only need visibility at the transmission–distribution interface, reducing costs to resource owners and LSEs.

These new approaches will require changes to the existing RA construct for CCAs to get credited for RA reduction or potentially eliminate the need to do so. Discussions and coordination among stakeholders, regulators, IOUs, and the CAISO will be required. These discussions will also need to address the CAISO backstop mechanism. The CAISO will only consider forgoing backstop procurement if it can be confident that DERs will be available and can verify performance.

Significant hurdles now prevent DERs from participating in the wholesale markets, limiting the usefulness of CCA-controlled DERs as a tool for meeting RA needs. The Commission, the CAISO, and stakeholders should work together to provide the CAISO with the appropriate level of visibility to DERs without making it cost-prohibitive for DER owners/operators to participate in the wholesale markets.

V. STAKEHOLDER RECOMMENDATIONS THAT EASE GRID CONSTRAINTS, REDUCE ENERGIZATION TIMELINES, MINIMIZE GRID UPGRADES, AND REDUCE COSTS SHOULD BE PRIORITIZED

In addition to prioritizing DER visibility to the CAISO for the reasons discussed in section IV above, the Commission should prioritize stakeholder recommendations that reduce energization delays and minimize the need to upgrade the distribution grid. IOUs are struggling with the timely energization of customer loads, resulting in significant delays for housing, data centers, commercial facilities, agricultural facilities, EV charging infrastructure, and many other projects. The expected growth in building and transportation electrification will require capacity upgrades to accommodate this new load. The Commission should pursue solutions that leverage DERs to maximize available capacity on the existing grid and offset costly grid upgrades.

The FGS Report includes stakeholder recommendations to prepare the grid for a high DER future, grouped into six topics/subtopics. CalCCA provides the following comments and recommendations for these topics, prioritized from highest to lowest.

1) Implementation of Flexible Generation Interconnection

Flexible generation interconnection enables more renewable generation and energy storage to interconnect to the grid without triggering grid upgrades by limiting their output when the grid is constrained. One such method of flexible interconnection is the recently approved Limited Generation Profiles (LGP).[13] LGP takes advantage of DER inverters' ability to adjust their output automatically in response to changes in the grid's available capacity. Renewable generation/storage developers must have reliable data on the available capacity of the grid where the resource will be interconnected to implement LGP. However, the information currently available in the IOUs' Integration Capacity Analysis (ICA) maps is too unreliable for LGP to be implemented. The Commission recently issued a decision[14] ordering IOUs to take steps to improve ICA accuracy, though it is uncertain when these changes will be implemented.

CalCCA supports the following stakeholder recommendations listed in the FGS Report[15] regarding improvements to ICA maps to support the implementation of LGP:

- An independent third party should provide oversight to ensure the usability and accuracy of ICA maps.
- The Commission should obtain additional support to ensure that Staff has the technical expertise to oversee the ICA maps.

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13 Resolution E-5296. Approving in part and modifying Pacific Gas and Electric Company's, Southern Edison Company's, and San Diego Gas & Electric Company's Advice Letters, submitted per Resolutions E-5211 and E-5230, providing the specifics and process of Limited Generation Profiles. (Mar. 21, 2024): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M527/K981/527981713.PDF.

14 See D.24-10-030, *Decision Adopting Improvements to Distribution Planning and Project Execution Process, Distribution Resource Planning Portals, and Integration Capacity Analysis Maps* (Oct. 23, 2024), at 152-159: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M544/K154/544154869.PDF.

15 FGS Report, at 39.

2) Roadmap for Distribution-Level Grid Services from Flexible Load Energization

The electrification of buildings and transportation is a critical component of the state's plan to reduce GHG emissions, but it also presents significant challenges to the distribution grid. IOUs are struggling with timely energization of new loads, some of which are triggering the need for new and upgraded circuits and substations. Flexible load energization can potentially reduce energization delays and should be a high priority for a high DER future grid.

Participants discussed two options for energizing flexible loads in Workshop 3. The first approach, firm import limits, is similar to the flexible generation interconnection discussed in section V.1 above. Establishing firm import limits allows the partial energization of flexible loads, so they do not need to wait for capacity upgrades to be completed before partially energizing their loads. The second approach, flexible (non-firm) load energization, envisions energizing loads that can provide flexibility to free up capacity for other loads. These flexibility services could be exchanged via bilateral agreements between loads or via a DER flexibility marketplace, as described in section II, above. CalCCA sees value in these approaches and supports efforts to implement these solutions as quickly as possible.

The following stakeholder recommendations listed in the FGS Report[16] regarding creating a roadmap for distribution-level grid services from flexible load energization should be adopted:

- The Commission should establish a statewide market platform for grid services from flexible load.
- The Commission should establish firm import limits using a process similar to that of LGP.
- The Commission should modify energization rules for load management technologies and limited load profiles.
- The IOUs should allow customers to negotiate agreements for sharing capacity on a constrained circuit with aggregators and/or other customers.

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16 FGS Report, at 39.

- The IOUs should establish dynamic hosting capacity.
- The IOUs should evaluate the opportunities for grid services from flexible loads earlier in the distribution planning process to develop operational flexibility.
- The IOUs should provide LSEs with better price signals, enabling them to use flexible demand to lower forecasted peak loads.

3) Data Sharing in a High DER Future

Section II, above, describes the need for a statewide data hub and DER registry to support the development of an open-access distribution grid, eventually leading to the animation of DER marketplaces. However, establishing a data hub will be challenging and may take years to implement. CCAs have long struggled to gain timely access to customer interval meter data, and the IOUs are still in the preliminary stages of launching their ADMS and DERMS, which are essential for the data hub. The cost, effort, and timeline should be weighed against other nearer-term alternatives, including DER marketplaces and improved ICA maps.

A DER registry modeled after the existing DG Stats registry may be achievable sooner. A database containing information on DER types, technical specifications, capabilities, and locations will be valuable for improved forecasting, planning, and program design.

CalCCA supports the following stakeholder recommendations listed in the FGS Report[17] regarding data sharing in a high DER future:

- The IOUs should provide access to data on DERs to non-IOU LSEs.
- The Commission should establish a statewide DER Registry that provides a centralized and standardized repository for DERs asset attributes, similar to the existing DG Stats system.

4) DER Visibility to the CAISO

See section IV, above, for CalCCA's comments and recommendations for creating DER visibility to the CAISO.

[17] *Id.*, at 50.

5) Scoping of IOU System Upgrades to Support Dynamic Rates

Dynamic rates provide another tool for CCAs to encourage flexibility in customers' energy usage patterns to reduce costs and ease grid constraints. CCAs are investigating and developing dynamic rates, which may provide additional load flexibility options for customers. However, structural and time constraints may limit CCAs' ability to offer dynamic rates that differ from IOUs' dynamic rate structures.

IOUs currently provide billing services for CCAs. It is still unclear how CCA dynamic rates will be integrated with IOUs' dynamic rate structures and the billing systems IOUs are developing to support them. If a CCA wants to develop a unique dynamic rate structure, it may need to develop the capabilities to calculate the charges for each billing interval. In that case, the CCA may need to integrate with the existing IOU billing system, have its own unique billing system, or pay the IOU to modify its billing systems to accommodate the CCA rate. The costs for either approach are still uncertain. Other currently open proceedings, such as PG&E's A.24-10-014,[18] present an opportunity for IOUs' billing system upgrades to be designed to enable robust dynamic rate structures. Billing system upgrades are complex, expensive, and infrequent. For these reasons, IOU billing system upgrades should be closely coordinated with the needs (including CCAs' needs) identified in this proceeding (R.21-06-017).

6) DER Visibility to DSOs

CalCCA does not oppose IOUs having visibility to DERs so long as it is not exclusive to IOUs. Under the bottom-up, layered system architecture, IOUs may not need visibility to every individual DER, however. IOUs are already implementing DERMS, enabling them to have visibility

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[18] *Application of Pacific Gas and Electric Company for Approval of Its Billing Modernization Initiative.(U39M)*, Application (A.) 24-10-014 (Oct. 23, 2024): https://apps.cpuc.ca.gov/apex/f?p=401:56::::RP,57,RIR:P5_PROCEEDING_SELECT:A2410014.

into DERs. Customers who enroll in IOU DER programs and tariffs can be automatically enrolled into the IOU DERMS, providing the necessary visibility. A statewide data hub can allow data sharing on DERs between LSEs, third-party owned or controlled DERs, the IOUs, and CAISO.

VI. THE FUTURE GRID STUDY REPORT SHOULD BE MODIFIED TO ACCURATELY REFLECT THE JOINT CCAS' WORKSHOP COMMENTS

The Joint CCAs' presentation at Workshop 1 provided examples of DER programs, described obstacles to optimizing programs to support grid needs, and offered suggestions for providing greater value to the distribution grid.[19] The FGS Report generally captures the Joint CCA points from the presentation, with one notable exception. The FGS Report correctly states that "CCAs lack sufficient information and incentives to optimize DER programs based on distribution system needs,"[20] but it fails to fully capture the challenge CCAs face. CCAs cannot optimize their DER programs to meet grid needs because they lack the proper economic signals and compensation. CalCCA therefore proposes changing the second bullet in the section "Joint Community Choice Aggregators (Joint CCAs)" on page 24 to read:

> CCAs lack sufficient information on distribution system needs and aligned economic incentives to develop new programs or optimize existing ones according to local system needs.

VII. CALCCA RESPONSES TO THE RULING QUESTIONS

1. The FGS Report includes a wide range of stakeholder input and recommendations from three public workshops. Please review the report (Attachment 1) to ensure it accurately reflects stakeholder input from the workshops. If there are discrepancies, please identify the sections, provide specific details and suggested corrections, and identify any inaccuracies, inconsistencies, or omissions from the workshop discussion in the sections of the FGS Report. Comments should be limited to workshop discussions and proposed recommendations.

See section VI, above, for CalCCA's response.

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19 Joint CCAs presentation: *Enabling DER Programs that Provide Distribution System Value: CCA Perspective* (Feb. 8, 2024), at 24.

20 *Ibid.*

2. The FGS Report outlines ten key operational needs, categorized as broad themes, which are essential for realizing a High DER future. These needs were identified based on insights and discussion from Workshop 1 - Identifying Operational Needs. (*Refer to Attachment 1, pages 24-29, "Outcome: Operational Needs for a High DER Future" section*.) Based on the stakeholder survey during workshop facilitation, the FGS Report findings show that the following three operational needs are considered high priority with sufficient urgency to justify implementation within 1-2 years:[21]

i. DER Visibility to the Distribution System Operator,
ii. DER dispatchability/control, and
iii. Open access to the distribution system

a) Do you agree that the above operational needs are the highest priority and need to be implemented within 1-2 years? If so, why?

CalCCA disagrees with this prioritization for reasons described in sections II, III, and IV, above.

b) If you disagree with any of the above-identified high priority needs, which three operational needs should be prioritized and why? Please include a timeline for implementation and explain your reasoning for supporting the priorities.

CalCCA proposes the following prioritization of the top three operational needs, described in further detail in sections II, III, and IV, above:

i. Open Access to the distribution system
ii. DER dispatchability/control
iii. DER visibility to the CAISO

3. Diverging approaches to enabling a High DER Future — Following Workshop 1, the workshop series highlighted a diverging approach to long-term visions for a High DER Future between the IOUs' top-down "grid orchestration" approach[22] where DSOs are central in coordinating DERs and the bottom-up, open-access vision[23] recommended by other stakeholders. *(Refer to Attachment 1, page 36, "Key Takeaways from Workshop 2".)*

a) Which approach do you support, the top-down "grid orchestration"

21 *See* FGS Report, at 29: Figure 12, Urgency of Implementing Operational Needs 29.
22 FGS Report, at 15-16, 30-35.
23 *Id.* at 21-23.

approach[24] or the bottom-up, open-access vision[25] for a High DER future? Please explain your reasoning for supporting the chosen approach and what steps should be taken in this proceeding to implement this vision. How do these steps align with the DSO's roles and responsibilities?

As discussed in section II, above, CalCCA supports the bottom-up, open-access approach to enable a high DER future.

b) How do the operational needs identified in question 2 above align with your recommendation for question 3 (a) above?

The operational needs identified in sections II, III, and III, above, directly support open access to the distribution grid. CalCCA's top operational need priority is open access to the distribution grid, followed by DER dispatchability/control, and finally, DER visibility to the CAISO. A longer-term objective of the open-access framework will be to animate DER marketplaces, increasing access for DERs to provide grid support. DER dispatchability is also a high priority, assuming it supports non-IOU dispatchability/control. Finally, an open-access framework enables access to the data necessary to support DER visibility to the CAISO.

c) Based on the discussions and perspectives presented during the workshop series, do stakeholders envision a hybrid approach that could bridge the gap between the IOU vision of grid orchestration and the bottom-up, open-access vision? If so, what might such a hybrid model entail?

One hybrid model will allow IOUs to orchestrate DERs only enrolled in an IOU program or tariff while providing non-IOU LSEs access to the grid, DERs, and customer meter data, as section II, above, details. The IOUs can target DER enrollment in areas where the grid is constrained to

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24 Topic 3a of Workshop 3 provides an opportunity for stakeholders to offer and discuss their ideas for new use cases for DER visibility to the DSO (key to grid orchestration).

25 Topic 4 of Workshop 3 provides an opportunity for stakeholders to offer and discuss their ideas for new use cases for potential distribution-level grid services market opportunities (key to bottom-up, open-access).

better manage demand on those circuits. This will include circuits experiencing extended energization delays and those requiring upstream capacity upgrades.

Providing grid, DERs, and customer meter data directly to LSEs or via a statewide data hub will enable open access to the distribution grid. LSEs and DER aggregators/developers can then operate DERs under their control to support grid needs. This will lead to the creation of DER marketplaces, expanding the pool of available DERs to support the efficient operation of a high DER grid. The ultimate step will be extending the marketplace to access the CAISO wholesale markets.

4. In Workshop 2, Assessing Gaps, the stakeholders focused on identifying gaps and barriers to achieving the operational needs from Workshop 1. During Workshop 2, the IOUs also presented roadmaps for DERs and/or Grid Orchestration and Automated Distribution Management Systems (ADMS) and DER Management Systems (DERMS) capabilities[26] in relation to the operational needs identified from Workshop-1. (*See pages 58-82 of Attachment 1, "APPENDIX A: OPERATIONAL NEEDS GAP ASSESSMENT" for a detailed assessment of the gaps.*) The following questions focus on operational needs and use cases articulated specifically for DER/Grid Orchestration by leveraging ADMS/DERMS capabilities.

a) Which operational needs and use cases can be operationalized by addressing gaps and barriers to DER/Grid Orchestration and ADMS/DERMS capabilities? How do these steps align with the DSO's roles and responsibilities?

CalCCA has no response at this time.

b) What specific steps should be addressed in this proceeding to advance DER operationalization? How do these steps align with the DSO's roles and responsibilities?

CalCCA has no response at this time.

c) The IOUs recommended a working group/task force(s) to collaborate on a framework that enables advanced DER/Grid Orchestration.[27] Do you agree with this recommendation, and if so, what are the key factors to consider in forming and setting goals for work products for this group? If you disagree, what alternative approaches should be

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26 FGS Report, at 30-35.

27 *Id.* at 15-16, 30-35.

considered?

CalCCA favors an open-access grid over the grid orchestration approach and disagrees with the need for a working group/task force to advance this framework. However, CalCCA supports a working group/task force to address the best approach to provide LSEs access to data on grid conditions, customer loads, and DERs, as discussed in section II, above. CalCCA also supports a working group/task force to develop strategies for animating DER marketplaces. Any working groups/task forces must have clear objectives, deliverables, timelines, and outcomes to ensure worthwhile effort.

d) In Workshops 1 and 2, the IOUs outlined a "grid orchestration" vision for a high-DER future. The terminology and Grid Modernization Plans (*See Attachment 1, Appendix B*) indicate a significant role for DSOs in orchestrating DERs. However, despite pilot work underway (See *Attachment 1, Appendix C*), there are still gaps in the timelines for developing and implementing operational capabilities. What improvements should be made to the ongoing pilot program? How can the ongoing and proposed pilots guide further actions to address the gaps? In your response, identify the gaps and the proposed enhancements.

CalCCA has no response at this time.

e) Is there a benefit in reviewing the five nearest-term pilot programs or functions the utilities can roll out and determining the technical requirements for those options? Explain your reasoning.

CalCCA has no response at this time.

5. The FGS Report compiled stakeholder recommendations as five topic summaries based on input and discussion during *Workshop 3 - Developing Recommendations to Address Gaps*. The FGS Report also includes Gridworks' recommendations for the next steps. (*Refer to the "Stakeholder Recommendations ..." and "Gridworks Recommended Next Steps ..." sections in Workshop 3, pages 39 – 51 of Attachment 1*.)

a) Please rank the five topics in order of priority and explain your reasoning ("1" being the highest priority). Please include subtopics 3a and 3b as you rank the five topics.

CalCCA provides the following rankings for the topic summaries, described in further detail in sections IV and V, above:

- Implementation of flexible generation interconnection;
- Roadmap for distribution-level grid services from flexible load energization;
- Data sharing in a high DER future;
- DER visibility to the CAISO;
- Scoping of IOU system upgrades to support dynamic rates; and
- DER visibility to the DSO.

b) Which recommendations from stakeholders and/or Gridworks do you support for each topic and why?

See CalCCA responses in section IV, above.

c) Regarding topic 3b in the FGS Report, DER Visibility to the CAISO, how do we ensure interoperability and visibility between the DSO and the CAISO for DER visibility to the CAISO?

CalCCA does not have a specific recommendation for this topic but supports further exploration of workable solutions.

d) Do you have recommendations on other operational needs that were not included in the final workshop?[28] If so, please list the operational need(s) and your specific recommendation.

CalCCA does not have recommendations for other operational needs that were not included in the FGS Report.

e) If any of your recommendations require coordination with other proceedings beyond the scope of the High DER Proceeding, please provide specific details about the necessary coordination, including the relevant proceedings and issues involved.

CalCCA does not have recommendations for requiring coordination with proceedings beyond those listed in Table 2, page 52 of the FGS Report.[29]

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[28] FGS Report, at 37.
[29] *Id*. at 52.

VIII. CONCLUSION

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

Respectfully submitted,

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

December 6, 2024

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company to Recover in Customer Rates the Costs to Support Extended Operation of Diablo Canyon Power Plant from September 1, 2023 through December 31, 2025 and for Approval of Planned Expenditure of 2025 Volumetric Performance Fees U 39 E	Application 24-03-018

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON PROPOSED DECISION

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

CALIFORNIA COMMUNITY CHOICE
ASSOCIATION
1121 L Street, Suite 400
Sacramento, CA 95814
Telephone (415) 302-2376
E-mail: regulatory@cal-cca.org

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

Counsel to
CALIFORNIA COMMUNITY CHOICE
ASSOCIATION

Dated: December 9, 2024

SUBJECT MATTER INDEX

TABLE OF AUTHORITIES

SUMMARY OF RECOMMENDATIONS

- The Commission should adopt the recommendations listed in CalCCA's[1] opening comments on the Proposed Decision.

- The Commission should direct PG&E to revise its VPF spending plan and propose projects consistent with the spending guidelines CalCCA describes in its reply brief and open a Phase 2 to allow parties to consider that plan.

- The Commission should not adopt SBUA's recommendation with respect to PG&E's attribute allocation proposal.

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1 Acronyms and defined terms used in the 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 to Recover in Customer Rates the Costs to Support Extended Operation of Diablo Canyon Power Plant from September 1, 2023 through December 31, 2025 and for Approval of Planned Expenditure of 2025 Volumetric Performance Fees U 39 E	Application 24-03-018

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
REPLY COMMENTS ON PROPOSED DECISION

The California Community Choice Association[2] (CalCCA) submits these Reply Comments on Administrative Law Judge Atamturk's *[Proposed] Decision on Pacific Gas and Electric Company's (PG&E) Revenue Requirement to Support Extended Operation of Diablo Canyon Power Plant and 2025 Volumetric Performance Fees Proposal* (PD or Proposed Decision) pursuant to Rule 14.3 of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission).[3]

With the exception of Conclusion of Law 13, which CalCCA recommends striking in its entirety for the reasons explained in its comments on the PD, CalCCA largely supports the PD and

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

3 Application (A.) 24-03-018, *[Proposed] Decision on Pacific Gas and Electric Company's (PG&E) Revenue Requirement to Support Extended Operation of Diablo Canyon Power Plant and 2025 Volumetric Performance Fees Proposal* (Nov. 14, 2024) (Proposed Decision).

recommends its adoption.[4] In these reply comments, CalCCA responds to two issues in parties' opening comments on the PD.

First, CalCCA agrees that the $167 million PG&E will collect in Volumetric Performance Fee (VPF) revenues during the record period should flow to customers as soon as possible, and therefore supports PG&E's recommendation for a Phase 2 to this proceeding. However, in order to ensure the benefits of PG&E's VPF revenues flow equitably to customers, the Commission should direct PG&E to revise its VPF spending plan consistent with the set of fundamental principles CalCCA and The Utility Reform Network (TURN) recommended (and which CalCCA discusses herein) before refiling that plan for the parties' and Commission's consideration in Phase 2.

Second, the PD's rejection of PG&E's attribute allocation proposal is sound, and only one party—the Small Business Utility Advocates (SBUA)—continues to support the adoption of PG&E's proposal. The Commission should not adopt SBUA's recommendation because that recommendation is not grounded in the scope of record of this proceeding, nor does it engage with the express language of Decision (D.) 23-12-036 directing PG&E to implement Resource Adequacy (RA) allocations to load serving entities (LSE) based on 12-month coincident peak (12 CP).

I. OPENING A PHASE 2 TO CONSIDER A REVISED VPF PLAN CAN ENSURE PRINCIPLED SPENDING THAT PROVIDES BENEFITS TO CUSTOMERS AS SOON AS POSSIBLE.

The VPF spending plan PG&E presents in this case is ill-conceived and lacks sufficient detail. Moreover, it does not comply with Section 712.8 (s) of the Public Utilities Code. PG&E's proposal to perform additional maintenance and increase staff at its hydroelectric generating

4 CalCCA Opening Comments on the PD at 1.

facilities would not provide any noticeable difference in service to retail customers in PG&E's service territory because when a hydroelectric generating facility goes on outage, the lost generation is replaced through CAISO market dispatch.[5] Further, PG&E's proposal raises competitive concerns to the extent PG&E uses VPF revenues to extend the life of its hydroelectric generation facilities. The record does not confirm whether, under PG&E's proposal, VPF funds will be used in a way that increases output from its hydroelectric generation assets or effectively extends the life of those assets. If either result occurs, PG&E's use of VPF funds would raise complex questions regarding the appropriate vintaging of PG&E's hydroelectric generating assets and whether PG&E would gain a competitive advantage over other LSEs in meeting its procurement requirements on account of revenue paid by all customers.

With that said, as PG&E points out in its comments on the PD, "[h]aving the VPFs idle in a balancing account does not benefit customers[.]"[6] Opening a second phase of this proceeding can expediently resolve the conflict between these two points: (1) the need to provide benefits to customers and (2) the gaps and shortcomings in PG&E's VPF plan. CalCCA therefore supports PG&E's suggestion in order to ensure the benefits of the $167 million in VPF revenues that PG&E will collect flow equitably to as many customers as possible as soon as possible. To that end, if the Commission opts to open a Phase 2, it will be well-served by directing PG&E to provide supplemental information regarding the slate of projects it has already proposed. Additionally, in this Phase 2, the Commission should direct PG&E to modify its list of candidate projects such that its Plan is consistent with the set of fundamental principles CalCCA and TURN recommended (as summarized in CalCCA's reply brief[7]). Specifically, the Commission should first direct PG&E to

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5 CalCCA-01 at 26, lines 12-18.
6 PG&E Comments on the PD at 3.
7 CalCCA Reply Brief at 9-11 (Oct. 21, 2024).

use VPFs to either offset capital investment or offset recorded expense spending that supports wildfire mitigation. Second, the Commission should direct PG&E to demonstrate that its VPF spending plan:

1. Benefits the maximum number of customers possible;
2. Prioritizes spending on electric distribution projects to help reduce upward pressure on distribution rates; and
3. Does not include spending on generation assets to avoid competition issues with other load-serving entities (LSE) in its service territory.

Again, as CalCCA explained its reply brief, while PG&E insists the Commission's review of VPF spending proposals must be limited to determining whether those proposals fit into one or more of the categories delineated in Section 712.8(s)(1) of the Public Utilities Code. Nothing in the statute or in D.23-12-036 precludes the Commission from adopting additional guardrails in this proceeding. And in fact, by adopting the guardrails TURN and CalCCA recommend *ahead of* any VPF plan refiling, the Commission can help streamline party evaluation of PG&E's proposals in on a compressed timeline.

II. THE COMMISSION SHOULD NOT ADOPT SBUA'S RECOMMENDATION WITH RESPECT TO ATTRIBUTE ALLOCATION

Rather than implementing the attribute allocation methodologies established by D.23-12-036, PG&E proposed to modify those methodologies in this proceeding. The PD correctly rejects PG&E's proposal,[8] and PG&E's Opening Comments on the PD do not oppose the PD's conclusion on this issue. That leaves the SBUA as the only party that continues to support PG&E's allocation proposal and recommend its adoption.[9] But SBUA's comments do not engage with the PD's logic

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[8] PD at COL 20.

[9] SBUA Comments on the PD at 6.

and analysis, the record of this proceeding, or even the plain language of D.23-12-036. Instead, SBUA simply "disagree[s]" with the PD's finding and offers the recommendation that the Commission "more strictly follow cost causation principles."[10]

The Commission should not adopt SBUA's recommendation. The PD's reasoning on this issue is both straightforward and sound: "PG&E's proposal does not comply with the implementation of the RA allocation methodology adopted in D.23-12-036, and therefore, it is rejected."[11] And SBUA's reference to "cost causation principles" suggests a fundamental misapprehension of cost causation; PG&E's proposal concerns the allocation of benefits, not the assignment of costs to cost-causers (which would implicate the cost causation principle). Moreover, as CalCCA's opening brief explains at length, there is no mismatch between costs and benefits here, because the statutory scheme conveys significant benefits exclusively to PG&E service area customers.[12]

III. CONCLUSION

For the reasons described in these comments, CalCCA respectfully urges the Commission to adopt the recommendations discussed herein as well as those presented in Appendix A to CalCCA's Comments on the Proposed Decision, and to grant any other relief the Commission deems just and reasonable.

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10 *Id*.

11 PD at 54.

12 CalCCA Reply Brief at 17-23.

Respectfully submitted,

/s/ Nikhil Vijaykar

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

Counsel to
CALIFORNIA COMMUNITY CHOICE ASSOCIATION

Dated: December 9, 2024

California Community Choice Association

SUBMITTED 12/10/2024, 12:13 PM

Contact
Lauren Carr (lauren@cal-cca.org)

1. **Please provide your organization's feedback on the changes being considered to the inputs and assumptions.**

The California Community Choice Association (CalCCA) appreciates the opportunity to comment on the November 19, 2024, modeling workshop. The California Independent System Operator (CAISO) proposes to make improvements to its inputs and assumptions for modeling hydro and forced outages. *First*, improving the methodology for modeling hydro by randomly drawing from 25 years of historical hydro years is worthwhile, as the CAISO demonstrated through sensitivity simulations that hydro assumptions have significant impacts on loss-of-load expectation (LOLE) events. *Second*, the CAISO indicates it will continue to update its forced outage rates and scrub its historical Outage Management System data. CalCCA supports the CAISO undertaking this effort, as it will be necessary to model forced outage rates accurately and use them for an eventual UCAP counting methodology. The CAISO's forced outage rates are lower than the California Public Utilities Commission's (CPUC's) and GADS's. For example, the CAISO forced outage rate for combustion turbines in 4.5 percent compared to 6.2 percent and 12 percent for the CPUC and GADS, respectively. These differences could have significant impacts on the modeling results, particularly for resources that are likely needed during reliability events.

CalCCA appreciates the CAISO's analysis of the correlation between load, solar, and wind in the 500 samples used in the reliability simulations. Comparison between the range of correlation coefficients reported by the CAISO and the correlation coefficients from the CPUC's 23 weather years[1] shows some discrepancies, as demonstrated in Figure 1. The most important difference is that the CPUC weather data shows multiple weather years with load-solar correlation coefficients that are below the range of 500 sampled years in the CAISO dataset. A lower correlation coefficient suggests a lower contribution of solar to reliability. The CAISO and the CPUC should evaluate this difference and determine if it is due to differences in the solar profiles or differences in the load profiles. The CAISO and the CPUC should also decide if their datasets should be adjusted to generate a wider range of load and solar correlations across samples.

Another difference is the solar-wind correlation coefficients: the small range in the CAISO dataset is more negatively correlated than in the CPUC dataset and varies much more narrowly than the solar-wind correlation in historical observations.[2] CAISO, in coordination with the CPUC, should evaluate whether adjustments to the sampling process are warranted based on these differences. These differences suggest that the CAISO's data sets, the CPUC's data sets, or both could require an update to ensure accuracy. The CAISO and the CPUC should coordinate to investigate these differences and align on data sources based upon their findings.

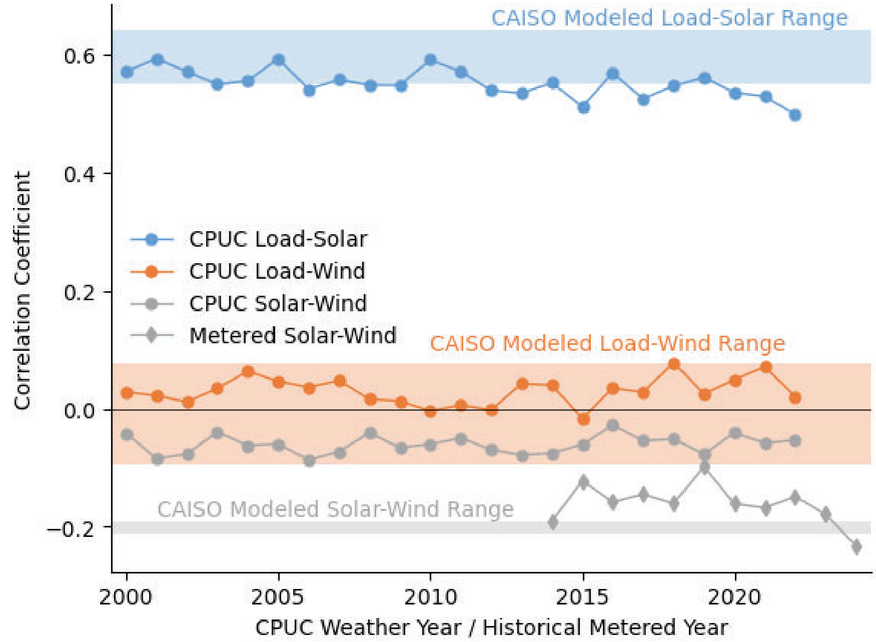

Figure 1. Discrepancies between Load, Solar, and Wind correlation coefficients between the CPUC's 23 weather years (dots), historical metered solar and wind (diamonds), and the range of correlation coefficients across all CAISO modeled samples (shaded area).

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[1] Downloaded from https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2024-26-irp-cycle-events-and-materials/system-reliability-modeling-datasets-2024. Load data is the CAISO Baseline load. Solar and Wind are aggregate of CAISO generators for the planning year of 2026.

[2] Historical metered data is from the CAISO production and curtailment data (https://www.caiso.com/library/production-curtailments-data). Curtailment data was used to estimate the pre-curtailment wind and solar correlations. We do not compare the metered wind and solar data to the metered CAISO load because the metered load embeds the behind-the-meter solar generation, producing different correlation coefficients than would be calculated with the consumption profiles.

2. Please provide your organization's input on preliminary mid-term and long-term results.

CalCCA appreciates the efforts of the CAISO and Astrapé to model mid-term and long-term reliability. The results demonstrate surplus capacity in 2026 through 2034. After removing surplus capacity to surface 1-in-10 LOLE, reliability events are concentrated in hours HE 18/19 and then again in HE 22. These separate reliability events appear to indicate a capacity need in the early evening hours when there is insufficient capacity to available to serve load and an energy need in the later evening hours when storage resources reach their energy limitations. One implication of these results is that loss-of-load events associated with depleted storage in HE 22 may be mitigated by actions that delay the discharge of storage, such as additional generation or reduction in demand in the hours immediately preceding HE 22.

The results suggest that "critical hours" should not be assumed as exclusively loss-of-load hours or exclusively gross peak hours, as described by E3. There are multiple ways critical hours can be accounted for within an RA program to ensure there is enough capacity and energy to meet reliability targets. The CPUC's slice-of-day program, for example, uses hourly capacity requirements and a storage charging sufficiency requirement. As the CAISO assesses near-term, mid-term, and long-term reliability needs in coordination with LRAs, it will become increasingly important to consider "critical hours" beyond peak hours to ensure reliability under a highly renewable and energy storage system.

3. Please provide your organization’s feedback on the capacity accreditation methods and PRM approaches presented today.

CalCCA appreciates the presentations from NP Energy, Astrapé Consulting, E3, and the CPUC Energy Division. The presentations provided a variety of different approaches for valuing RA capacity. As stated in CalCCA’s December 5, 2024, comments to the Issue Paper, the CAISO should provide opportunities for all LRAs to adopt the same resource counting methodologies and accompanying PRMs and availability incentives. The CAISO, in coordination with LRAs, should seek to count resources in a manner that puts all technology types on a level playing field by accurately reflecting their capabilities in their NQC values in both the year-ahead and month-ahead timeframe. They should also demonstrate that proposed changes to NQCs are accompanied by revisions to the PRM.

4. Please provide any feedback not already captured.

CalCCA has no additional feedback at this time.

California Community Choice Association

SUBMITTED 12/12/2024, 02:36 PM

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

1. **Please provide a summary of your organization's general comments on the Discussion Paper and November 14 meeting.**

   The California Community Choice Association (CalCCA) appreciates the opportunity to comment on the California Independent System Operator's (CAISO) Congestion Revenue Rights (CRR) Discussion Paper. CalCCA supports the CAISO taking on an initiative to ensure the CRR market design achieves the foundation purposes set by Federal Energy Regulatory Commission and CAISO precedent.[1] The comments herein recommend, in summary, that the CAISO:

   - Consider battery energy storage system (BESS) load as eligible loads and eligible sinks in the allocation process;
   - Evaluate how to change its CRR product definitions, either by redefining the hours of peak and off-peak or adding additional products; and
   - Explore CRR auction efficiency to determine if a change to the auction is needed to ensure CRRs can be effectively used as hedges by entities engaging in forward energy contracting and minimize systemic losses paid for by transmission ratepayers.

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   [1] Discussion Paper at 3 and 5.

2. **Please provide your organization's comments on the tentative working group schedule found on slides 8 and 36 of the presentation from the November 14 meeting.**

   CalCCA supports the tentative working group schedule. The working group will progress through foundations, analysis, policy scope, problem statements, and an issue paper by the second quarter of 2025. This provides the right amount of time to discuss the issues before turning to the policy development phase.

3. **Are there any topics that your organization would find it especially helpful to devote time to at future working group meetings? These could be topics covered in the discussion paper, topics that came up in the November 14 meeting, or topics not covered at all so far. Any specific level setting topics on the history or current CAISO processes and procedures related to CRRs?**

   The CAISO should have one working group meeting on level-setting, including the current CAISO processes and the use of CRRs in hedging, and at least one working group meeting on analysis depending on the volume of requests for analysis put forth by stakeholders. The CAISO should also hold working group meetings that allow parties to present their own proposals, including more in-depth presentations on the proposals put forth in the stakeholder catalog and other proposals parties develop during the working group process.

4. **Are there any topics that your organization would find it especially helpful to devote time to at future working group meetings? These could be topics covered in the discussion paper, topics that came up in the November 14 meeting, or topics not covered at all so far. Any**

level setting topics on the use of CRRs in hedging that you would like to present (or would like to see presented by others)?

See response in section 3 above.

5. **Please provide your organization's comments on the draft problem statements listed in the Discussion Paper and discussed at the November 14 meeting. Does your organization have any proposed changes or additional proposed problem statements?**

New Problem Statement

The CAISO should add the following problem statement: BESS storage load is not considered an eligible load or eligible sink under tariff section 36.8.2.

While pumped storage load is considered an eligible load and eligible sink under the tariff, BESS load is not. Load-serving entities (LSE) with pumped storage in their portfolios are allocated a potentially significant amount of CRRs to hedge congestion to their storage loads. Meanwhile, LSEs with BESS loads do not receive the same treatment. This appears inequitable and disadvantages LSEs with BESS in their portfolios. Within this initiative, the CAISO should consider treating grid charged BESS loads the same as pumped storage loads for the purposes of the CRR allocation, as no distinguishing characteristics between pumped storage and BESS have been identified to justify different treatment.

Product Definition

The CAISO should explore its CRR product definitions within this initiative. As stated in the problem statement, the current on-peak and off-peak definitions may adversely impact the ability to hedge congestion risks. The CAISO defines peak and off-peak CRRs in its Business Practice Manual as follows:

- On normal weekdays, Monday through Saturday, off-peak hours are the hours ending 1 through 6 and hours ending 23 and 24; on-peak hours are the hours ending 7 through 22.
- Public holidays and Sundays are treated as off-peak. That is, all 24 hours on these days are off-peak.

As renewables on the system have increased, the CAISO's load shape and generation patterns have changed, affecting energy flows and congestion patterns on the system. This initiative should evaluate how to change the definitions, either by redefining the hours of peak and off-peak or adding additional products (e.g., a new super-peak product or additional products).

CalCCA agrees with the California Department of Water Resources (CDWR) that the current definitions do not align well with how the grid has evolved. While CDWR recommends splitting the on-peak time-of-use into super peak (HE 17 HE21) and on-peak (HE07 HE16, and HE22), the CAISO must perform an analysis before defining new products and/or hours. This initiative should map energy flows by hour to determine if there is a logical way to refine the product definitions and their time periods.

With more solar generation on the grid, there is a need to examine whether additional periods should be defined. Since LSEs seek to hedge the risk of congestion on solar output which will only occur in daylight hours, the current definitions of on-peak and off-peak do not address the expected operational hours. The CDWR proposal does not address solar hours either. The Intercontinental Exchange (ICE) transacts standard solar contracts, one that is Monday-Saturday excluding holidays and another that is seven days a week. Both define the hours of settlement as HE 09 – HE 16. If the CAISO is going to examine changing the hours of the CRR product, it should include in scope other changes to better accommodate needed hedging given the changing output profile of generation.

Auction Efficiency

The CAISO should also explore CRR auction efficiency within this initiative. As stated in the problem statement, the CRR auction only yields about 65 cents per dollar of congestion revenue. The data provided by the CAISO and DMM is helpful and appreciated. However, more about the issue must be understood prior to any changes. For example, the CAISO currently has a "set aside" of CRRs from imports after each of the allocation processes (annual and monthly). In some cases, LSEs are able to get CRRs in the auction that they were not able to obtain in the allocation. It is not clear whether this is due to the “set aside” or due to some other cause. Before LSEs can evaluate the efficacy of changes to the CRR auction and allocation process, it is important to understand why LSEs are unable to obtain some CRRs in the allocation that they later obtain in the auction.

6. Please provide your organization’s comments on any additional analysis or data you believe would help develop the problem statements and why.

The CAISO should: (1) analyze energy flows by hour to identify a logical way to redefine or add products to account for changes in system peak and off-peak hours; (2) work with individual LSEs to identify the reason(s) they were not able to obtain CRRs in the allocation process but later did obtain them in the allocation, as described in section 5; and (3) provide further information on the amount and cause of CRR revenue insufficiency.

First, regarding the flows to inform time of use for CRRs, the CAISO should evaluate whether congestion on source-sink pairs routinely change direction at a consistent time. For example, it is possible that flows change when solar resources begin generating at sunrise and stop generating at sunset. If this is causing a significant change in flows on the grid, then changing CRR periods is increasingly important. In addition, the CAISO should examine congestion on battery storage as most of its output occurs during the net load peak. The CAISO could then evaluate whether a super-peak product, like the one recommended by CDWR, would cover such a need or if a different product is needed.

Second, regarding LSEs unable to obtain CRRs in the allocation but later obtaining them the auction, it would be helpful to identify why that outcome occurs. For example, is the CRR set-aside impacting the ability to get CRRs in the allocation? As an alternative to examining each case in which an LSE requested a CRR in the allocation but did not get it, the CAISO could model whether those CRRs would have been granted to the LSE in allocation had the DMM proposal for the changes to the auction and its resulting impacts on the allocation process been in place.

Third, regarding revenue insufficiency, it would be helpful to know how much of the insufficiency is due strictly to the current auction process. The CAISO could evaluate those CRRs that would have been allocated to LSEs under the DMM proposal (as discussed in the prior paragraph) and determine if there is any revenue insufficiency and if so, how much.

These data points would be helpful to LSEs in determining how the proposals advanced in this initiative so far improve load’s ability to hedge congestion risk under the proposed changes.

7. Please provide any additional comments.

CalCCA has no additional comments at this time. 43

California Community Choice Association

SUBMITTED 12/13/2024, 01:01 PM

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

1. **BAA Grouping Approach: Please provide your organization's feedback on the proposed BAA grouping methodology for market power mitigation:**

   a) Do you support grouping BAAs to assess competitiveness? Why or why not? b) What changes, if any, would you recommend for the testing approach? c) What changes, if any, would you recommend for determining the competitive LMP?

   The California Community Choice Association (CalCCA) appreciates the opportunity to comment on the California Independent System Operator's (CAISO's) Balancing Authority Area (BAA) Level Market Power Mitigation (MPM) working group discussions. CalCCA supports the grouping approach for assessing BAAs for competitiveness as presented by the CAISO at its November 6, 2024, working group meeting. This approach will improve the CAISO's BAA-level MPM methodology by including available supply from other BAAs in its test for competitiveness. CalCCA agrees this will better reflect actual market conditions and competitive dynamics.

   The CAISO should continue to use the dynamic competitive path assessment (DCPA), which uses a three pivotal supplier test to test for competitiveness under the grouping approach. While some stakeholders expressed concern with the grouping approach because a BAA could pass individually but fail as a group, this outcome is not a flaw with the grouping approach. For example, assume an MPM test of a group with two BAAs:

<u>**BAA 1**</u>	<u>**BAA 2**</u>	<u>**Combined**</u>
Load: 1000 MW	Load: 2500 MW	Load: 3500 MW
G1: 150	**G11: 850**	G1: 150
G2: 150	**G12: 850**	G2: 150
G3: 150	**G13: 850**	G3: 150
G4: 150	G14: 100	G4: 150
G5: 150	Total Gen: 2650 MW	G5: 150
G6: 150		G6: 150
G7: 150		G7: 150
G8: 200		G8: 200
G9: 200		G9: 200
G10: 200		G10: 200
Total Gen: 1650 MW		**G11: 850**
		G12: 850
		G13: 850
		G14: 100
		Total Gen: 4300

   In this example, the following conclusions can be drawn:

   - On its own, BAA 1 does not have any pivotal suppliers and should be competitive;
   - On its own, BAA 2 has pivotal suppliers (Load cannot be met without G11, G12, and G13)
   - If BAA1 and BAA2 were combined, G11, G12, and G13 are still pivotal as the 3500 MW load will need all three to operate even if all other resources are operating.

   Therefore, even though BAA 1 could pass if it <u>*were tested*</u> on its own, in reality, there is direct transfer capability between BAA 1 and BAA 2. This means supply from BAA 1 is available to serve BAA 2 load and vice versa.

Therefore, because the combined BAA 1 and BAA 2 load cannot be met without G11, G12, and G13, the group fails the three pivotal supplier test and supply in BAA 1 and BAA 2 should be subject to mitigation.

The CAISO should include the CAISO BAA in the grouping approach. In doing so, the CAISO BAA would be treated like any other BAA rather than assumed to be competitive. If there is the potential for the CAISO BAA to be structurally uncompetitive in some hours, the CAISO should have a mechanism to mitigate against the exercise of market power. The ability to mitigate market power when there is the potential for suppliers to exercise it will ensure ratepayers are protected against excessively high costs. At the same time, there is little risk of resources not recovering their costs with the CAISO BAA included in the grouping approach, as MPM only mitigates uncompetitive hours, not every hour, and it only mitigates bids that are above the resources' default energy bids (DEBs) or the competitive locational marginal price (LMP). For these reasons, the CAISO BAA should be tested for competitiveness under the grouping approach.

2. Pivotal Supplier Treatment: Please share your feedback on the concepts for identifying and mitigating pivotal suppliers:

a) Should mitigation only apply to pivotal suppliers, or should it extend to all suppliers in uncompetitive BAAs? b) What are your thoughts on dynamically evaluating pivotal groups to identify pivotal suppliers?

The CAISO should not only apply mitigation to pivotal suppliers. It should instead extend mitigation to all suppliers in uncompetitive BAAs, as it currently does under its system MPM in the Western Energy Imbalance Market and its local MPM for the CAISO BAA. CalCCA agrees with the reasons presented by the CAISO to mitigate all suppliers in uncompetitive BAAs.[1] The presence of pivotal suppliers indicates structural issues with market competitiveness within a BAA, and non-pivotal status does not mean a supplier cannot exercise market power. The CAISO should not risk adding computational time or introducing opportunities for gaming or collaboration by modifying its methodology to mitigate only pivotal suppliers.

The CAISO states that arguments against mitigating non-pivotal suppliers may include the following: (1) non-pivotal suppliers, by definition, cannot unilaterally influence market outcomes because small suppliers are price takers and coordination becomes increasingly difficult with three or more suppliers; and (2) mitigation of non-pivotal suppliers could be seen as overly restrictive market intervention by suppressing price signals and discouraging efficient market entry/investment.[2] However, the CAISO MPM is already designed to address these concerns by only mitigating uncompetitive hours, not every hour, and only mitigating bids that are above the resources' default energy bids (DEBs) or the competitive LMP. Therefore, if a small supplier is a price taker or its bid price equals its marginal cost, MPM should have no effect on the price the supplier receives as it would receive its DEB, which should equal its marginal cost plus a buffer, or the competitive LMP if the competitive LMP is higher than the resource's DEB. For these reasons, the CAISO should not apply MPM to only pivotal suppliers.

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[1] November 21, 2024, presentation at 20.

[2] *Id.,* at 21.

3. Impact Test Implementation: Please comment on the proposed "impact test" in the BAA-level mitigation framework:

a) Do you support including an impact test? Why or why not? b) What are your thoughts on impact thresholds and how they may vary based on: • Frequently constrained areas • System emergency conditions • Peak versus off-peak periods • Absolute ($/MWh) or relative (%) thresholds

The CAISO should not include an impact test that tests whether a generator's bidding behavior *both* deviates from expected competitive levels *and "materially affects market prices*." CalCCA does not support only mitigating offers with LMP impacts above a defined threshold, as stakeholders have not demonstrated the need for such a change that could result in increased ratepayer costs. Again, MPM mitigates only uncompetitive hours and only bids that are above the resources' DEB or the competitive LMP. DEBs ensure that the mitigated resources still recover their costs. Lack of an impact test would, at worst, result in mitigated bids that would cover all costs of providing the energy in the market. If the market clearing price is higher than the resources' DEB, including those that were mitigated and those that were not, resources would still receive market clearing price and any applicable rents where that market clearing is above their marginal cost.

While the CAISO states that this proposal could help avoid "over-mitigation," the concept of over-mitigation does not make sense with the way the CAISO applies MPM. Assuming over-mitigation means mitigating resources' bids when the market is competitive, then over-mitigation would have no impact on market outcomes. In a competitive market, the marginal resource would be expected to bid its DEB (which includes costs and a margin above costs for profit)[1], and that DEB would set the market clearing price that all other resources would receive. In an uncompetitive market, resources with the ability to exercise market power would be mitigated to their DEBs or the competitive LMP.

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[1] Economic theory for a competitive market would dictate that the resource bid its short-run marginal cost which would not include a margin above those costs for a level of profit that may be included in the DEB. Therefore, it is more likely that CAISO's MPM process results in a price level that if anything is slightly above the competitive outcome. See section 39.7.1 of the CAISO Tariff.

4. Implementation Timeline:

a) What are your thoughts on targeting a straw proposal by May 2025? b) What changes, if any, would you suggest for the working group sequence?

CalCCA supports the CAISO's timeline of May 2025 for a straw proposal. The CAISO should prioritize the implementation of BAA-level MPM improvements, including testing the CAISO BAA for BAA-level MPM, ahead of the other two scoping items. Implementation of BAA-level MPM improvements should occur, at the very latest, at the same time as the implementation of scarcity pricing revisions so that generators with the potential to exercise market power cannot do so in a manner that triggers scarcity pricing without the ability for the CAISO to properly prevent such actions.

5. Other Comments: Please provide any additional feedback not addressed in the sections above.

CalCCA has no other comment at this time.

California Community Choice Association

SUBMITTED 12/13/2024, 01:01 PM

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

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5. Other Comments: Please provide any additional feedback not addressed in the sections above.

CalCCA has no other comment at this time.

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 2025 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U39E)

Application 24-05-009

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON PROPOSED DECISION

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION
1121 L Street, Suite 400
Sacramento, CA 95814
Telephone: (415) 302-2376
E-mail: regulatory@cal-cca.org

Nikhil Vijaykar
Tim Lindl
Keyes & Fox LLP
580 California Street, 12th Floor
San Francisco, CA 94104
Telephone: (408) 621-256
E-mail: nvijaykar@keyesfox.com
tlindl@keyesfox.com

December 2, 2024

Counsel to
CALIFORNIA COMMUNITY CHOICE ASSOCIATION

SUBJECT MATTER INDEX

TABLE OF AUTHORITIES

Commission Decisions

Commission Rules of Practice and Procedure

SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

- In light of recent changes in the RA[1] market—including scarcity in the System RA market, sharp increases in short-term RA prices and (correspondingly) the RA MPBs, and the implementation of the Commission's Slice-of-Day framework—CalCCA does not oppose revisiting the RA MPB calculation methodology in a separate proceeding following the conclusion of this ERRA Forecast proceeding, as set forth in the PD. That proceeding should include adequate timelines and discovery rights for non-IOU parties, *i.e.*, parties without immediate access to IOU data, to develop their own proposals.

- Any Commission inquiry into the RA MPB calculation methodology should, however, also consider other necessary modifications to the PCIA framework for valuing the IOUs' capacity portfolios. As the IOUs' pending ERRA Forecast proceedings demonstrate, the parties have widely divergent perspectives on necessary modifications to the IOUs' capacity portfolio valuation practices to address the aforementioned RA market dynamics. Importantly, the Commission should consider changes to both *price* (*i.e.,* the RA MPBs) as well as *quantity* (*i.e.,* the categorization and quantum of RA to which MPBs are applied).

- As a part of that rulemaking, the Commission should also consider revisiting other unresolved but important policy issues associated with the current PCIA framework and not being addressed in any other proceeding to ensure the Commission holistically improves that framework. Among other issues, the Commission should consider addressing and aligning the utilities' common cost allocation practices in that rulemaking.

- The PD errs when it adopts PG&E's proposed common cost allocation methodology. PG&E's methodology does not ensure that common costs are assigned to the customer groups causing those costs. Instead, it would exacerbate existing cost shifts and create new cost shifts. Further, *by adopting PG&E's proposal, the PD effectively perpetuates the very "cost shift" it identifies and seeks to eliminate because PG&E's proposal would **retain** the status quo common cost allocation methodology for certain non-ESA common costs.*

- The Commission should therefore direct PG&E to adopt CalCCA's proposed common cost allocation methodology based on gross revenue requirements, and should consider aligning the utilities' common cost methodologies in a future rulemaking.

- The PD correctly rejects PG&E's proposal to apply a modified common cost allocation methodology effective January 1, 2024, but the Commission should clarify that PG&E is prohibited from modifying 2024 common cost allocations.

- The Commission should direct PG&E to correct the errors CalCCA identified in PG&E's October Update via its December 2024 Final AET.

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

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 2025 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U39E)	Application 24-05-009

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON PROPOSED DECISION

California Community Choice Association[2] (CalCCA) submits these Comments on Administrative Law Judge Fox's *[Proposed] Decision Approving Pacific Gas and Electric Company's 2025 Energy Resource Recovery Account Related Forecast Revenue Requirement and 2025 Electric Sales Forecast* (PD) pursuant to Rule 14.3 of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission) and the procedural schedule established in the Assigned Commissioner's Scoping Memo and Ruling.[3]

The PD largely stays within the boundaries of ERRA Forecast proceedings and rejects PG&E's proposal to deviate from the Commission's settled Power Charge Indifference Adjustment (PCIA) framework by implementing a Resource Adequacy (RA) Market Price Benchmark (MPB) cap. With that said, the PD reasonably acknowledges that the Commission might consider concerns related to the RA MPBs in a separate proceeding.[4] Indeed, significant recent changes in the RA market have occurred, including (1) System RA market scarcity; (2)

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

[3] Assigned Commissioner's Scoping Memo and Ruling at 5 (Aug. 1, 2024) (Scoping Memo).

[4] PD at 10; *see also* Scoping Memo at 3 ("The Commission acknowledges that the RA MPB Issue may merit additional consideration in a rulemaking.").

sharply increased market prices and MPBs; and (3) the implementation of the Commission's Slice-of-Day (SOD) framework. CalCCA therefore does not oppose the Commission reassessing the valuation of the IOUs' capacity portfolios in a policy proceeding outside of this docket.

To the extent the Commission undertakes that inquiry, however, it must broaden its lens and address discrete issues beyond the System RA MPB calculation methodology that the Commission and parties have flagged for future resolution both in this year's ERRA forecast cases and in prior years' cases. First, in order to ensure that customers—bundled and departed—continue to fairly share the benefits of the IOUs' capacity portfolios and maintain indifference consistent with the requirements of state law, the Commission should consider a range of important but discrete issues related to the IOUs' capacity valuation practices. The Commission should inquire into both *price* (*i.e.*, System, Local and Flex RA MPBs) as well as *quantity* (*i.e.*, the categorization and amount of RA to which the price is applied). Contrary to PG&E's assumption that the RA MPBs overestimate the value of its capacity portfolio, as discussed in these comments, a more methodical assessment may reveal that the IOUs' portfolios are in fact undervalued. A PD in SCE's ERRA Forecast proceeding recognizes the need for this broader scope by including more issues for future resolution than just the RA MPB methodology.[5]

Further, to ensure that parties have a meaningful opportunity to evaluate a range of policy solutions, and comprehensively compare and contrast practices across utilities, the Commission should open a rulemaking on these issues (rather than considering these issues in parallel Phase IIs of the pending IOU Forecast proceedings). That rulemaking should allow parties full discovery rights and ensure a sufficient timeline for non-IOU parties to develop their own proposals.

Second, the IOUs' common cost allocation practices also merit scrutiny in a rulemaking. In this proceeding, PG&E proposed to modify its current common cost allocation methodology to align with SCE's methodology (which, itself, is not Commission-approved). Modifications to SCE's methodology are not within the scope of this proceeding, however, and nor is SCE a party to this proceeding. Therefore, parties to this proceeding (including CalCCA) had no meaningful opportunity to probe SCE's allocation methodology.[6] Meanwhile, in San Diego Gas and Electric

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5 A.24-05-007, Proposed Decision at 76-77.

6 Moreover, the ALJ in SCE's ERRA Forecast proceeding ruled the common cost allocation issue beyond the scope of that proceeding, so parties had no opportunity to test SCE's approach in *that* proceeding. *See* A.24-05-007, Assigned Commissioner's Scoping Memo and Ruling, at 2-3 (Aug. 14, 2024).

Company's (SDG&E) ERRA Forecast proceeding, that utility proposed to modify *its* common cost allocation methodology to align with PG&E's methodology, before ultimately landing on an approach that does not align with either PG&E's or SCE's methodologies.[7] The utilities' incomplete, halting, and half-hearted attempts to align allocation methodologies with one another should send a clear signal to this Commission that this issue is ripe for consideration in a rulemaking. The PD in SDG&E's ERRA Forecast proceeding rightly recognizes this—it finds the parties' (both SDG&E and CCA parties) common cost allocation proposals in that proceeding

> will benefit from better examination in a separate proceeding involving the three major IOUs and where all impacts can be better understood. This will ensure that the issue can be more thoroughly examined and any resulting directives can be made applicable to the three major IOUs uniformly.[8]

Until the Commission scrutinizes the IOUs' common cost allocation methodologies in a rulemaking, it should replace PG&E's existing approach with CalCCA's proposed allocation methodology, which allocates common costs to generation-related balancing accounts based on the gross revenue requirements associated with each account. CalCCA's proposed methodology is the very methodology PG&E advanced in last year's ERRA Forecast proceeding. As PG&E itself asserted in that proceeding, the gross revenue requirement methodology "will ensure that all customers bear an equitable portion of costs to manage the shared generation portfolio" and "eliminate[s] the risk that bundled customers bear a disproportionate share of [ESA] costs."[9] The methodology PG&E advances in <u>this</u> proceeding, in contrast, will exacerbate existing cost shifts, create new cost shifts, and perpetuate the *very* cost shift the PD identifies, and therefore, the PD errs where it adopts that methodology.[10]

<u>Third</u>, PG&E also proposed to apply its proposed common cost allocation methodology effective January 1, 2024. As the PD correctly observes, however, the rates in question (2024 rates, reflecting the PG&E's current common cost allocation methodology) have already been adopted, and PG&E should not be permitted to undo those rates via a proposal introduced in this year's

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7 A.24-05-010, Updated Prepared Direct Testimony of Sheri Miller on behalf of SDG&E at SM-4.

8 A.24-05-010, Proposed Decision at 33.

9 A.23-05-012, Pacific Gas and Electric Company's (U 39 E) Response to Administrative Law Judge's Ruling Directing Parties to Comment Regarding Fixed Generation Costs (Aug. 16, 2023).

10 PD at 34.

proceeding.[11] The Commission should, however, clarify that PG&E must not change 2024 common cost allocations via 2025 rates, including the 2024 true-up included in those rates.

Finally, CalCCA identified two errors in PG&E's Fall Update testimony and brought those errors to PG&E's attention via its comments on the Fall Update. PG&E corrected those errors in its preliminary Annual Electric True-Up (AET),[12] but in the interest of clarity, the Commission should expressly direct PG&E to ensure it corrects those errors in its December 2024 Final AET.

I. TO THE EXTENT THE COMMISSION REVISITS THE RA MPB CALCULATION METHODOLOGY, IT SHOULD ADDRESS OTHER OUSTANDING ISSUES

The PD directs PG&E to use the 2024 MPBs for inclusion in rates and the calculation of the PCIA,[13] consistent with the PCIA framework established in D.18-10-019 and D.19-10-001. It also correctly points out that PG&E's RA MPB mitigation proposals are not in scope in this proceeding,[14] but states the Commission "may in another proceeding consider revisions to the MPB methodology that may impact the adopted 2025 Final MPBs."[15] Finally, the PD directs Energy Division (ED) to conduct an inquiry into swap and affiliate transactions and report on transactions that should not be included in the MPBs.[16]

The PD largely gets this issue right. PG&E's MPB mitigation proposal—an *ad hoc* change to the established PCIA framework—is the kind of broad policymaking the Commission has routinely deemed beyond the scope of ERRA Forecast proceedings, including in this proceeding itself.[17] It also puts the cart before the horse. As CalCCA has recommended on several occasions, the Commission should first consider whether revisions to the MPB calculation methodology are warranted—a step CalCCA does not oppose in light of recent changes in the RA market and sharp increases in RA prices. Then, to the extent revisions are necessary, the Commission should apply MPBs calculated through a revised methodology in subsequent ERRA Forecast proceedings.[18] The

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11 *Id.* at 37.

12 PG&E Advice Letter 7426-E.

13 PD at 21.

14 *Id.* at 10.

15 *Id.* at 22.

16 *Id*.

17 Scoping Memo at 3.

18 *See e.g.,* Reply Brief of California Community Choice Association at 4 (Oct. 31, 2024).

PD nods to the first step of that process where it states the Commission may consider revisions to the MPB methodology in another proceeding.

But the Commission should not limit the scope of that future proceeding to MPB methodology revisions. As this proceeding and the other IOUs' pending ERRA Forecast proceedings have made evident, changes in the RA market (such as the implementation of SOD) and increases in the RA MPB have prompted IOUs and CCAs to raise other possible changes to the PCIA framework that might be necessary to ensure indifference. These changes can ensure that the costs and benefits of the IOUs' capacity portfolios are reasonably estimated and shared between bundled and departed customers. Moreover, prior Commission decisions in past ERRA Forecast cases, ERRA Compliance Cases, and the PCIA rulemaking have noted discrete issues within the existing framework that require resolution outside of the siloed ERRA proceedings.

Critically, the Commission should consider not only changes to *price* (the MPB calculation), but also changes to the *quantity* to which the MPB is applied. That is because the product of price and quantity is what ultimately produces the *value* of the IOUs' capacity portfolio. Getting that *value* number right is the key to ensuring that the Commission maintains indifference. Importantly, whereas PG&E assumes that revising the MPB calculation methodology will reduce the value of its capacity portfolio, a holistic assessment may indeed reveal that PG&E's capacity portfolio is currently *<u>undervalued</u>*.

With respect to *quantity*, the Commission should consider the impact of SOD and assess whether Net Qualifying Capacity (NQC) is still the right measure of RA quantity. In SCE's ERRA Forecast proceeding, that utility put forward a proposal tied to SOD that increased the value of its portfolio by $352 million.[19] Parties have yet to access the data needed to explore the impacts of SCE's proposal on PG&E's portfolio, but if that proposal is adopted as a best practice, the value of PG&E and other utilities' capacity portfolios may also significantly increase. The Commission should also consider the categorization of RA (*i.e.*, System, Flex, or Local) and its impact on quantity. The IOUs currently take inconsistent approaches to assigning the capacity in their respective portfolios into the System, Flex or Local categories, and not all IOUs value capacity based on *how it is actually used* (rather than its theoretical category). If PG&E were required to do

[19] A.24-05-009, CalCCA Comments on the Fall Update, p. 5 (Nov. 12, 2024).

so, the value of PG&E's capacity portfolio would *increase* by $1 billion.[20] Finally, the Commission should consider eliminating the Local RA benchmark altogether. In SCE and PG&E's service territories, the only entity procuring Local RA resources is the Central Procurement Entity (CPE), and the costs and benefits of those resources flow through the Cost Allocation Mechanism (CAM), not the PCIA. Again, if the Commission were to eliminate that benchmark, the value of PG&E's RA portfolio is likely to increase.

With respect to *price*, CalCCA has neither had the time nor the discovery opportunity to investigate other approaches and determine their impacts across the three service territories. These approaches include: (1) establishing a monthly MPB for System RA; (2) revising the benchmark calculation such that capacity is valued based on its highest value, not just its theoretical category, since an LSE is likely to use an attribute based on its highest value; and, (3) to the extent the Commission retains the Local RA benchmark, considering whether the current methodology for calculating both the Local and Flex MPBs accurately reflect market prices.[21]

The PD in SCE's ERRA Forecast proceeding rightly recognizes the importance of considering these RA price- and quantity-related issues in a broad future rulemaking. It concludes that "ripe for consideration within a rulemaking proceeding" are: (1) the methodology for assigning RA capacity to the System, Local and Flex RA subcategories for the purpose of valuation; (2) whether hourly RA MPB prices are needed; and (3) how to achieve proper accounting for storage and hybrid resources under SOD.[22] The scope of the Commission's inquiry into the RA MPB methodology, therefore, should include an evaluation of these broader RA quantity and subcategorization-related issues.

While a discrete set of targeted changes to the price and quantity terms used to value the IOUs' capacity portfolios merit the Commission's consideration, the Commission might also consider alternate approaches to addressing the same set of objectives (*i.e.,* ensuring indifference and the establishment of just and reasonable rates for bundled and unbundled customers). To the extent the Commission wants to avoid having to constantly revise the methodology for valuing

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20 *See* A.24-05-009 et al., CalCCA Notice of Ex Parte Communication at 22 (Nov. 20, 2024). The $1 billion impact is derived by applying the System RA MPB, rather than the Local RA MPB, to resources PG&E categorizes as Local RA for the 2025 Indifference Amount in its October Update. Applying the System RA MPB increases the value of PCIA resources by $1.06 billion.

21 CalCCA Comments on the Fall Update at 20.

22 A.24-05-007, Proposed Decision at 76-77.

IOU capacity portfolios as the RA and renewable energy markets evolve—by far the most repeatedly controversial issues in ERRA Forecast proceedings—it might consider proposals to avoid the issue altogether. Those proposals might include allocating the attributes of the IOUs' portfolios and charging the costs themselves—or allowing load serving entities (LSE) the flexibility to manage their portfolios—rather than arguing over administratively-established proxy values.

Finally, the Commission should also consider bringing into scope of a future rulemaking other persistent PCIA-related policy issues. The utilities' respective common cost allocation methodologies, for instance, warrant the Commission's attention in a rulemaking. As the PD in SDG&E's ERRA Forecast proceeding acknowledges, the utilities' respective common cost allocation methodologies

> will benefit from better examination in a separate proceeding involving the three major IOUs and where all impacts can be better understood. This will ensure that the issue can be more thoroughly examined and any resulting directives can be made applicable to the three major IOUs uniformly.[23]

Beyond common cost allocation, other outstanding PCIA-related policy issues requiring resolution include: (1) a framework to revintage utility-owned PCIA-eligible resources;[24] (2) the use and valuation of pre-2019 banked Renewable Energy Credits (REC);[25] and (3) establishing the ERRA Compliance proceedings as the appropriate venue in which to consider whether executed

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23 A.24-05-010, Proposed Decision at 33.

24 *See* D.23-11-069 at 511, Ordering Paragraph 44 (The final decision in PG&E's Phase I General Rate Case states: "with respect to Joint CCAs' framework proposal [for revintaging existing utility-owned assets], the Commission also declines to consider it in this proceeding, as this would require a thorough examination of the complexities involving the current vintaging framework and how costs are allocated as part of the PCIA. This review would best take place in a broader proceeding in which other utilities and stakeholder positions may be considered."); A.25-05-015, *et al., Proposed Decision*, at 391-392 (Oct. 18, 2024) (In the proposed decision in SDG&E's Phase I General Rate Case, the Commission similarly denies the same PCIA framework proposed in PG&E's case, concluding it would be better for consideration in a future rulemaking).

25 *See* D.24-08-004 at 3-5 ("While we recognize that parties have different perspectives about the direction in D.19-10-001 and its applicability to pre-2019 RECs, we do not have the record to fully evaluate them here. We may consider the issue in a future rulemaking."); *see also* D.23-06-006, Section 8 (declining to consider the issue in R.17-06-026).

contract amendments warrant revintaging.[26] These issues were not resolved in the PCIA Rulemaking (R. 17-06-026), which is now closed. As a practical matter, there exists no other forum in which the Commission might consider these policy issues.

A new PCIA rulemaking aimed at resolving these discrete issues would finally provide the forum to address all of these issues. These policy issues should not be addressed in parallel Phase IIs of the IOUs' pending ERRA Forecast proceedings. A rulemaking would instead ensure that all three utilities are respondents, elicit the involvement of a broad set of parties, and ensure parties have a meaningful opportunity to compare and contrast utility practices, issue discovery, and develop proposals. While CalCCA would not oppose a timeline to ensure changes to the PCIA framework can be adopted prior to next year's Fall Updates, non-IOU parties require sufficient time and discovery rights to be able to develop their own proposals. A rulemaking best provides those mechanisms.

II. THE PROPOSED DECISION COMMITS FACTUAL ERROR IN FINDING THAT PG&E'S COMMON COST ALLOCATION PROPOSAL BETTER ALIGNS COST RECOVERY WITH THE CUSTOMER GROUPS RESPONSIBLE FOR THE COSTS

In this proceeding, PG&E proposes to modify its methodology for allocating its "Common Costs" across generation-related balancing accounts. PG&E's "Common Costs" consist primarily of costs associated with its Energy Policy and Procurement (EPP) personnel as those individuals spend time on bidding, scheduling, and dispatching generation resources and bundled customer load in the California Independent System Operator (CAISO) market (collectively, PG&E's Electric Supply Administration or "ESA" costs). PG&E's current methodology allocates ESA costs across three generation-related balancing accounts: the ERRA, the Portfolio Allocation Balancing Account (PABA), and the New System Generation Balancing Account (NSGBA), based on each account's <u>net revenue requirement (*i.e.*, costs net of benefits)</u>. That means the *value* of the generation resources in each account—including energy, RA, and Renewable Portfolio Standard (RPS) value—impacts the magnitude of ESA costs allocated to each account.

In recent years, those impacts have been dramatic and led to unintended results. Therefore,

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[26] D.21-07-013 at 21 ("[T]he Commission's currently open proceeding, Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment, R.17-06-026, is more appropriate for considering how the Commission should address contract vintages for the utilities in the future, and we intend to explore these matters in that proceeding."); *but see* D.23-06-006 at 45 (failing to resolve and appearing to misunderstand the order set forth in D.21-07-013).

CalCCA agrees that PG&E's Common Cost allocation methodology must change, even though a change would cause community choice aggregator (CCA) and other departed customers to bear a relatively greater share of PG&E's ESA costs under current market conditions. CalCCA proposed to replace the net revenue requirement allocation methodology with a gross revenue requirement allocation methodology. That methodology would continue to allocate PG&E's ESA and other Common Costs to ERRA, PABA and NSGBA, but would do so based only on the costs of the generation resources in each account, without accounting for the offsetting *value* of those resources. The gross revenue requirement methodology eliminates the impact of fluctuating energy, RA, and RPS value on ESA cost allocation, ensuring no customer group avoids paying their fair share of ESA costs when the value of PG&E's generation portfolio increases. Conversely, no customer group would be saddled with a disproportionate share of PG&E's ESA costs if the value of its portfolio decreases. Importantly, the gross revenue requirement methodology follows cost causation principles because it reasonably allocates costs based on the activities driving those costs—namely, the generation resources in PG&E's portfolio.

PG&E supported the gross revenue requirement allocation methodology just a year ago. In its prepared testimony in the 2024 ERRA Forecast proceeding, PG&E stated the gross revenue requirement methodology "align[s] cost responsibility for the ESA costs required to manage PG&E's generation-related portfolio and bundled positions with expected generation-related portfolio and bundled position costs."[27] A couple months later, in response to an ALJ ruling regarding the IOUs' fixed generation costs, PG&E again supported the gross revenue requirement methodology. PG&E asserted the gross revenue requirement methodology: (1) "eliminate[s] the risk that bundled service customers bear a disproportionate share of [Common Costs]"; (2) asserted that methodology is "supported by statutory requirements to prevent cost shifting"; and (3) argued that methodology "will ensure that all customers bear an equitable portion of costs to manage the shared generation portfolio."[28]

Since that testimony, however, PG&E has changed its tune. PG&E now proposes to revert the allocation of non-ESA Common Costs to the net revenue requirement methodology, and largely split ESA costs between the Legacy Utility Owned Generated (UOG) and 2009 PCIA

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[27] A.23-05-012, PG&E Prepared Testimony at 9-10:9-11.

[28] A.23-05-012, PG&E Response to Administrative Law Judge's Ruling Directing Parties to Comment Regarding Fixed Generation Costs at 7 (Aug. 16, 2023).

vintages based on the GRC revenue requirement of resources in those vintages. In defense of its proposal, PG&E asserts it wants to align its ESA cost allocation approach with SCE's "approved" methodology, but ignores that the Commission has not, in fact, approved SCE's ESA cost allocation methodology.

The PD finds PG&E's existing net revenue requirement methodology "results in a significant cost shift from bundled customers to unbundled customers" based on the premise that 95 percent of shared costs are allocated to the bundled customers who represent about 37 percent of load share. The PD goes on to find that "PG&E's Revised Proposal better aligns the share of costs with the customer groups most responsible for the costs, is appropriately aligned with the methodology that SCE uses, and is subject to less market price variation than the CalCCA proposal."[29] The PD's discussion, findings and conclusions on this issue include multiple errors and requires revision.

First, PG&E's allocation proposal conflicts with Section 365.2 of the California Public Utilities Code because it would exacerbate an existing cost shift between bundled and unbundled customers. As Table 1 in PG&E's rebuttal testimony demonstrates, under its proposal, PG&E would allocate the vast majority of ESA costs—over 87 percent— to the PCIA.[30] PG&E confirmed that its EPP organization performs activities like bidding, scheduling, and/or dispatching resources not only for PCIA-eligible resources, but also for CAM resources and other resources, in addition to scheduling PG&E's bundled load in the CAISO market.[31] In other words, ESA costs relate to activities that go beyond the management of PCIA-portfolio resources.

Assigning nearly all ESA costs to the PCIA as PG&E proposes would require departed load customers to pay a proportional share of <u>all</u> ESA costs, ignoring the fact that a portion of those costs provide no benefit to departed load customers.[32] For example, to the extent PG&E

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[29] PD at 34.

[30] PG&E would allocate only a small portion of ESA costs to CAM, based on the UOG revenue requirements associated with the single UOG CAM facility. *See* Exh. CalCCA-02C (PG&E response to CalCCA discovery request 4.09b). And PG&E would allocate a similarly small portion of ESA costs—relating to PG&E's gas supply activities—to ERRA. Exh. PG&E-02 at 23. In 2025, the total ESA cost allocation to ERRA and CAM would be $11,927,000, whereas the total ESA cost allocation to the PCIA would be $80,866,000—approximately 87 percent of total ESA costs.

[31] Exh. CalCCA-01C, Attachment B (PG&E's response to CalCCA data requests 1.28 and 1.34).

[32] Exh. CalCCA-01C at 13.

incurs ESA costs to support new resource procurement for today's bundled customers, or incurs ESA costs to schedule bundled load into the CAISO market, unbundled customers (including those who departed bundled service many years ago) would be required to pay nearly 60 percent of those costs.[33] This would require unbundled customers to contribute to costs that were not incurred on their behalf, violating the ratepayer indifference principle established in California law.[34]

Unfortunately, PG&E's cost tracking processes are not set up in a manner that would allow the utility to perfectly delineate the Common Costs it incurs for PCIA, CAM, or ERRA-related activities, nor does PG&E track time spent administering contracts by PCIA vintage.[35] This inhibits the Commission's ability to exactly match cost allocation to cost-causing activities. In response to CalCCA discovery requests, PG&E confirmed it does not track time associated with ESA costs in a manner that would allow it to determine the percentage of ESA costs incurred on bundled customers' behalf, let alone allowing it to confirm that percentage is equal to bundled customers' load share of 36.7 percent.[36]

As such, the Commission should not aim to adopt an allocation methodology that matches cost allocation with load share because there is simply no evidence in the record to suggest that customers' load share bears a direct relationship to the drivers of PG&E's ESA cost. In fact, PG&E readily acknowledges that the costs of administering its energy supply portfolio "do not necessarily scale with load increases, and in some cases may increase with increased load departure,"[37] emphasizing that allocating Common Costs in a manner that matches load share is neither logical nor equitable. Therefore, the PD errs in its findings that (1) PG&E's existing methodology creates a cost shift based on a mismatch between allocation and load share percentages;[38] and (2) that PG&E's proposed methodology would remedy that cost shift.[39]

Absent more granular data that tracks ESA cost by resource, the most equitable approach

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[33] Exh. PG&E-3 at 23 (Table 1, demonstrating that departed load would pay 57.4% of total ESA costs in 2025 under PG&E's revised cost allocation proposal).

[34] Cal. Pub. Util. Code sections 365.2, 366.2.

[35] Exh. CalCCA-01C at 14, Attachment B (PG&E's response to CalCCA discovery requests 1.19, 1.29 and 1.35).

[36] Exh. CalCCA-02C (PG&E response to CalCCA data request 4.14).

[37] *Id*. (PG&E response to CalCCA data request 4.16).

[38] PD at 34; Finding of Fact 3.

[39] PD at Finding of Fact 4.

to allocating ESA costs is to allocate those costs based on the total revenue requirements of the generation-related balancing accounts. That approach would allocate ESA costs based on the EPP group's main tasks, including (1) responding to procurement requirements; (2) contracting the resources necessary to respond to those requirements; (3) scheduling and bidding those resources at CAISO; and (4) settling the resulting transactions. That approach would allocate ESA costs across balancing accounts and vintages based on which customers' behalf procurement activities are undertaken.

Indeed, PG&E's proposed methodology—which would allocate Common Costs to PABA and CAM vintages based on the UOG GRC revenue requirements associated with each vintage[40]—implicitly acknowledges the reasonableness of allocating Common Costs based on revenue requirements (as opposed to load share). However, PG&E never explains why the Commission should adopt an allocation methodology based only on the UOG GRC revenue requirement associated with each balancing account, as opposed to total revenue requirements. The only defense PG&E offers for that approach is that it mimics SCE's ESA-equivalent cost allocation methodology, which—as these comments describe above—the Commission has not approved.

As the Commission decides this issue, it should consider how establishing a policy in this case will impact future allocations of costs attributable only to bundled customers, and how PG&E's approach would violate State law prohibiting cost-shifts. Eliminating all cost shifting is not possible given the nature of the tasks and the fact PG&E does not track the customers on whose behalf those tasks are completed. However, CalCCA's gross revenue requirement methodology best minimizes cost shifts and matches the costs of both existing resources *and* future resources to the customers to whom those resources will provide benefits.

Second, PG&E's service territory is different from SDG&E's, for example, because PG&E's service territory has PCIA-exempt customers—largely made up of Direct Access customers. PG&E's revised Common Cost allocation proposal would not only exacerbate the cost shift described above but would also unfairly shift costs away from such PCIA-exempt customers. In response to a CalCCA discovery request, PG&E confirmed its PCIA-exempt customers represent 6.9 percent of PGE&'s total system forecast load.[41] Those customers would not pay for

[40] Exh. CalCCA-02C (PG&E response to CalCCA discovery request 4.07).

[41] *Id*. (PG&E response to CalCCA discovery request 4.09).

ESA costs allocated and recovered through PG&E's PCIA rates, they would only pay for ESA costs allocated to CAM.[42] Under PG&E's proposal, however, only 3.3 percent[43] of ESA costs would be allocated to CAM in 2025, because the allocation of costs to CAM would be based on the GRC revenue requirements of a single CAM facility—the Elkhorn UOG facility—which represents a negligible fraction of PG&E's total CAM capacity.[44] The GRC revenue requirements of that facility ($38,372,000)[45] represent only 13 percent of the total 2025 CAM revenue requirement ($302,203,000) presented in PG&E's prepared testimony.[46] PCIA-exempt customers would pay approximately 6.9 percent of the CAM-allocated costs, or 0.2 percent of PG&E's total ESA costs.

In contrast, CalCCA's gross revenue requirement methodology would require that PCIA-exempt customers pay a more equitable share of ESA costs, because it would allocate ESA costs to CAM based on the revenue requirements associated with the entire CAM portfolio—not just a single resource. This makes good sense because PG&E incurs ESA costs associated with its entire generation portfolio (including contracted resources), and not with just the subset of resources reflected in GRC revenue requirements. Under the gross revenue requirement methodology, 5.4 percent of ESA costs would be allocated to CAM and paid for by all customers subject to CAM charges. By adopting CalCCA's proposed allocation methodology, therefore, the Commission can avoid creating a new cost shift from PCIA-exempt customers.

Third, PG&E's Revised Proposal purports to depart from PG&E's existing Common Cost allocation methodology, but would in fact *retain the status quo net revenue requirement methodology for the allocation of PG&E's non-ESA Common Costs (collateral costs).*[47] *Thus, by adopting PG&E's proposal, the PD effectively perpetuates the very "cost shift" it identifies and seeks to eliminate.*

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42 *Ibid*.

43 *See* Exh. PG&E-3 at 23, Table 1 ($3,045,000 allocated to CAM, divided by a total $92,793,000 in ESA costs in 2025, which equals 3.28 percent).

44 *See* Exh. PG&E-1C at 5-18 (Table 5-6).

45 PG&E Rebuttal Workpapers A.48 and A.51.

46 Exh. PG&E-2 at 9-4, Table 1.

47 *See* PD at 32, noting that SCE allocates Common Costs to its ERRA, NSGBA, and PABA according to the net revenue requirement in each account; and at 34, adopting PG&E's Revised Proposal because it is "appropriately aligned with the methodology that SCE uses."

Finally, adopting CalCCA's proposal in this proceeding does and should not preclude the Commission from scrutinizing and seeking to align the IOUs' common cost allocation methodologies in a future rulemaking proceeding. Indeed, the PD in SDG&E's ERRA Forecast proceeding acknowledges the merit in undertaking this comprehensive review. If the Commission desires to align the IOUs' common cost allocation approaches, that future rulemaking provides the correct avenue for the Commission to do so.

III. THE COMMISSION SHOULD CLARIFY THAT PG&E SHOULD NOT REVISE 2024 COMMON COST ALLOCATIONS VIA 2025 RATES

PG&E proposed to apply modifications to its common cost allocation methodology effective January 1, 2024. CalCCA objected to PG&E's proposal, noting that rates reflecting PG&E's existing methodology have already been established, and PG&E should not be permitted to abuse the true-up by using it to change the allocation methodology.

The PD correctly concludes that PG&E should not adopt its proposal starting with January 1, 2024, because the rates in question have already been adopted. However, the PD creates ambiguity when it adopts PG&E's allocation proposal "beginning with January 1, 2025, rates."[48] That sentence creates ambiguity because PG&E's proposal—including the portion of that proposal seeking to change the common cost allocations embedded in <u>2024</u> rates—would have been implemented via <u>2025</u> rates. The Commission should therefore clarify that PG&E is prohibited from modifying the common cost allocations embedded in 2024 rates. Instead, the Commission should clarify that PG&E may apply the new common cost allocation methodology to the 2025 forecasted indifference amount (and then going forward to both future year-end PABA balances and forecasted indifference amounts). Changes in Appendix A effectuate this intent.

IV. PG&E SHOULD MAKE AGREED-UPON CORRECTIONS PRIOR TO THE IMPLEMENTATION OF 2025 RATES

CalCCA found two errors in PG&E's Fall Update, which it describes in comments on the Fall Update.[49] First, PG&E did not calibrate the price input assumption for two ModCAM contracts (it did not use the correct MPB). Second, PG&E used an erroneous MPB to determine the value of banked RECs it will use in 2025 to meet its minimum retained RPS requirements.

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48 *Id.* at 37.

49 CalCCA Comments on the Fall Update at 24.

After initially suggesting it would wait until the implementation of 2026 rates to correct those errors, PG&E's workpapers show the utility appears to have addressed those errors in its Preliminary AET advice letter for 2025 rates.[50] For the avoidance of doubt, the Commission should order PG&E to fix its errors as a part of 2025 ERRA Forecast rate implementation, via the December 2024 Final AET.

V. CONCLUSION

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

Respectfully submitted,

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

December 2, 2024

Counsel to CALIFORNIA COMMUNITY CHOICE ASSOCIATION

50 PG&E Advice Letter 7426-E.

APPENDIX A

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

Findings of Fact

3. PG&E identified ~~a cost shift~~ unintended results associated with the methodology it uses to allocate Common Costs.

4. The~~is~~ ~~cost shift~~ flaws associated with PG&E's Common Cost allocation methodology would be remedied by the adoption of ~~PG&E's Revised~~ CalCCA's Proposal.

Conclusions of Law

2. It is reasonable to adopt ~~PG&E's Revised~~ CalCCA's Proposal for a Common Cost allocation methodology beginning with January 1, 2025, rates.

X. It is not reasonable for PG&E to revise the allocation of Common Cost allocations reflected in 2024 rates.

Ordering Paragraphs

X. PG&E is directed to correct the errors CalCCA identifies in its comments on PG&E's Fall Update via the implementation of 2025 rates.