FEBRUARY FILINGS

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2024 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation. (U39E)	Application 23-05-012
And Related Matters.	Application 23-07-012 Application 23-06-001 Application 23-05-013

CALIFORNIA COMMUNITY CHOICE ASSOCIATION, SAN DIEGO COMMUNITY POWER, AND CLEAN ENERGY ALLIANCE'S JOINT OPENING BRIEF

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

Counsel for California Community Choice Association

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

Counsel to San Diego Community Power and Clean Energy Alliance

February 3, 2025

TABLE OF CONTENTS

TABLE OF AUTHORITIES

California Public Utilities Commission Proceedings

California Public Utilities Commission Decisions

California Public Utilities Commission Rulings

SUMMARY OF RECOMMENDATIONS

- The Commission[1] should not modify the definition of FGC set forth in the August 1, 2023, Ruling Directing Comments.

- While the type and quantity of FGC will vary among the three IOUs, the Commission should ensure that similar costs are recovered in a consistent manner. To do so, any consideration of proposals to change the recovery of FGC should only occur in proceedings in which all three IOUs are parties.

- The Commission need not develop a methodology for determining FGC.

- The Commission does not need to require additional reporting with regard to FGC. If the Commission establishes a reporting requirement, it should develop a uniform template that could be used consistently across IOUs.

- The Commission should take up the issue of Common Cost allocation in a non-expedited proceeding in which all IOUs are parties.

---

[1] Acronyms and defined terms used in the Summary of Recommendations are defined in the body of this joint Opening 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 2024 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation. (U39E)	Application 23-05-012
And Related Matters.	Application 23-07-012 Application 23-06-001 Application 23-05-013

CALIFORNIA COMMUNITY CHOICE ASSOCIATION, SAN DIEGO COMMUNITY POWER, AND CLEAN ENERGY ALLIANCE'S JOINT OPENING BRIEF

Pursuant to the April 2, 2024, *Assigned Commissioner's Scoping Memo and Ruling*[2] (Scoping Ruling), and the May 1, 2024, *Administrative Law Judge's Ruling Amending the Schedule for the 2024 ERRA Forecast Proceeding as Consolidated to Consider Issues Related to Fixed Generation Costs*,[3] California Community Choice Association (CalCCA), San Diego Community Power (SDCP), and Clean Energy Alliance (CEA) (collectively, the CCA Parties) hereby submit this joint Opening Brief in the consolidated Track 2 of the above-captioned proceedings (Track 2).

The record in Track 2 reflects near consensus that the Commission need not take additional steps to define, or otherwise develop methodologies or rules related to, Fixed Generation Costs

---

2 Application (A.) 23-05-012, A.23-07-012, A.23-06-001, and A.23-05-013, *Assigned Commissioner's Scoping Memo and Ruling* (Apr. 2, 2024); *see also* A.23-05-012 et al., *Assigned Commissioner's Scoping Memo and Ruling* (Oct. 11, 2024) (clarifying that this proceeding was consolidated for the purpose of addressing Fixed Generation Cost issues).

3 A.23-05-012, et al., *Administrative Law Judge's Ruling Amending the Schedule for the 2024 ERRA Forecast Proceeding as Consolidated to Consider Issues Related to Fixed Generation Costs*, at 2-3 (May 1, 2024).

(FGC) in this proceeding. Indeed, the CCA Parties, San Diego Gas & Electric Company (SDG&E), and Pacific Gas and Electric Company (PG&E) all concur that the California Public Utilities Commission's (Commission) existing definition of FGC is reasonable and Southern California Edison Company (SCE) did not propose any alternative definition.[4] Further, all parties agree that no additional reporting is necessary,[5] and the CCA Parties and each investor-owned utility (IOU) agree that the Commission need not develop additional rules at this time.[6]

While the parties agree that the Commission should not take any action with respect to FGC in this proceeding, the Commission should nevertheless scrutinize the IOUs' allocation of procurement-related "Common Costs"[7] in a non-expedited proceeding in which all IOUs are parties. PG&E raised Common Cost allocation in its Track 2 Prehearing Conference Statement (Track 2 PHCS) in this proceeding.[8] The Assigned Commissioner determined Common Cost allocation was

---

[4] A.23-05-012 et al., Exhibit (Exh.) CCA-01: *Prepared Direct Testimony of Brian Dickman on Behalf of the California Community Choice Association, San Diego Community Power, and Clean Energy Alliance* in the 2024 Consolidated Track 2 ERRA Forecast Proceeding, at 4:30-31 – 5:1-2 (Oct. 8, 2024); A.23-05-012 et al., Exh. PG&E-7: *Pacific Gas and Electric Company 2024 ERRA Forecast – Consolidated Track 2 Rebuttal Testimony*, at 3:27-28 – 4:1-14 (Nov. 22, 2024) (recommending a minor correction to clarify the Commission's existing definition); A.23-05-012 et al., Exh. SDGE-18: *Prepared Rebuttal Testimony of Sheri Miller on Behalf of San Diego Gas & Electric Company*, at SM-1:16-21 (Nov. 22, 2024); Exh. SCE-09: A.23-05-012 et al., *Rebuttal Testimony of Southern California Edison Company in Support of its Energy Resource Recovery Account (ERRA) 2024 Forecast Operations*, at 4:7-12 (Nov. 22, 2024).

[5] Exh. CCA-01 at 11:6-18; Exh. PG&E-7 at 9:4-15; Exh. SDGE-18 at SM-2:11-16; Exh. SCE-09 at 6:1-2; A.23-05-012 et al., Exh. AReM-01: *Testimony of Mark Fulmer on Behalf of the Alliance for Retail Energy Markets Concerning Definition and Treatment of Fixed Generation Costs*, at 9:3 (Oct. 8, 2024).

[6] Exh. CCA-01 at 11:22-23; Exh. PG&E-7 at 10:4-5; Exh. SDGE-18 at SM-2 – SM-4; Exh. SCE-09 at 6:3-8.

[7] PG&E's Common Costs are costs related to its procurement activities and include Energy Supply Administration (ESA) costs, as well as carrying costs related to collateral requirements and greenhouse gas (GHG) emissions compliance instruments (collateral costs) (*see* PG&E Prehearing Conference Statement at 3; *see also* Decision (D.) 24-12-038 at 30); SCE's Common Costs similarly relate to the cost of its Energy Procurement & Management (EPM) organization, as well as collateral carrying costs (*see* D.24-12-038 at 31); SDG&E's Common Costs, which SDG&E calls "Procurement Operations and Maintenance," relate to the functions of SDG&E's Procurement Group (*see* D.24-12-040 at 32).

[8] A.23-05-012, A.23-07-012, A.23-06-001, and A.23-05-013, *Prehearing Conference Statement of Pacific Gas and Electric Company* (U 39 E), at 3-6 (Jan. 5, 2024).

outside the scope of Track 2 because no other IOU had raised a similar issue at that time.[9] Subsequently, however, two out of the three IOUs (PG&E and SDG&E) proposed changes to their Common Cost allocation methodologies in their respective 2025 ERRA Forecast proceedings.

The Commission attempted to achieve consistency with respect to the IOUs' Common Cost allocation methodologies through its Final Orders in the 2025 ERRA Forecast proceedings, but recognized that Common Cost allocation proposals required additional examination in a separate proceeding involving all three IOUs such that "the issue can be more thoroughly examined and any resulting directives can be made applicable to the three major IOUs uniformly."[10] Thus, the Commission should revisit the IOUs' Common Cost allocation practices in a non-expedited proceeding in which all IOUs are parties to provide sufficient process to further develop the record on that issue.

I. THE COMMISSION DOES NOT NEED TO TAKE ADDITIONAL ACTION WITH REGARD TO THE FGC CONSIDERED WITHIN THE SCOPE OF THIS PROCEEDING

A. The Commission's Existing Definition of FGC Should Not Be Modified

Scoping Item 1a. asks whether the Commission should modify its definition of FGC.[11] In its August, 1, 2023, Ruling Directing Comments, the Commission defined FGC as "costs that do not change based on the amount of electricity customers use or the amount of operating time associated with the electricity generation."[12] This definition is reasonable and appropriate because it correctly distinguishes between costs which are driven by customer usage (variable costs) and costs which are

---

9 Scoping Ruling at 6 (stating the Common Cost allocation PG&E raised "may not align across utilities").

10 D.24-12-040 at 33.

11 Scoping Ruling at 7.

12 *Administrative Law Judge's Ruling Directing Parties to Comment Regarding Fixed Generation Costs*, A.23-05-012, at 1 (Aug. 1, 2023); A.23-06-001, *Administrative Law Judge's Ruling Directing Parties to Comment Regarding Fixed Generation Costs*, at 1 (Aug. 1, 2023); A.23-05-013, *Administrative Law Judge's Ruling Directing Parties to Comment Regarding Fixed Generation Costs*, at 1 (Aug. 1, 2023).

not directly driven by customer usage (fixed costs).[13] Moreover, the Commission's existing definition is broad enough to accommodate differences in IOU-specific costs or language.[14]

It is important to note that while some FGC would be required for an IOU to serve the hypothetical "last remaining bundled customer," FGC should decline over time with declining bundled customer load.[15] While the rate at which FGC decline may not be linear – *i.e.*, directly proportional to the consumption of electric services – this does not necessarily implicate a cost shift.[16] This is because these costs are currently spread to both bundled and departed load customers through existing cost recovery mechanisms such as the Energy Resource Recovery Account (ERRA) and Portfolio Allocation Balancing Account (PABA).[17]

B. While the Type and Quantity of FGC Will Vary Between IOUs, the IOUs Should Recover Similar Costs in a Consistent Manner

Scoping Item 1b. requests feedback as to which FGC should be consistent among the three IOUs.[18] In response to the Commission's Ruling Directing Comments,[19] the IOUs provided information as to how they account for seven main categories of FGC.[20] The IOUs' comments demonstrated that there is some variation in the type and quantity of FGC incurred by each IOU.[21] However, despite these differences, each IOU explained that most FGC are recovered from *all* customers through existing cost recovery mechanisms.[22]

---

13 Exh. CCA-01 at 4:30-31 – 5:1-2; *see also* Exh. PG&E-7 at 3:27-28 – 4:1-2.
14 Exh. SDGE-18 at SM-1:19-21.
15 Exh. CCA-01 at 5:3-7.
16 *Id*. at 5:11-18.
17 *Id*. at 5:14-18.
18 Scoping Ruling at 7.
19 A.23-05-012, A.23-06-001, and A.23-05-013, Ruling Directing Comments.
20 *See* Exh. CCA-01 at 7, Table 1.
21 *Id*. at 6:14-15, Table 1.
22 *Id*. at 7:2-4.

While the type and quantity of FGC will vary between IOUs, similar costs should be recovered in a transparent and consistent manner among all three IOUs.[23] As this brief discusses in Section II below, the Commission should ensure that proposals to change how FGC are recovered should only occur in proceedings in which all IOUs are parties.[24] By doing so, the Commission will avoid piecemeal treatment of similar FGC, and will allow for greater procedural efficiency by allowing for direct comparison between all IOUs.

C. The Commission Does Not Need to Develop any Methodology by Which the IOUs Determine FGC

Scoping Item 1c. asks whether the Commission should adopt a methodology by which the IOUs determine FGC.[25] The Commission need not adopt such a methodology at this time, as nearly all FGC categories are already spread among all customers, rendering superfluous any effort to standardize the determination of FGC.[26] In particular, any fixed electric generation charges flow through the Power Charge Indifference Adjustment (PCIA) for PCIA-eligible resources and are recovered from bundled and unbundled customers as a matter of course.[27] Even if zero bundled customers remained, the costs of PCIA-eligible utility-owned generation, including FGC, would be recovered through California Independent System Operator (CAISO) market revenues and PCIA rates.[28]

If the Commission ultimately finds it necessary to develop a methodology to determine FGC, it should develop that methodology in a non-expedited proceeding in which all IOUs are parties.

---

[23] *Id*. at 9:1-4.
[24] *Id*. at 9:4-6.
[25] Scoping Ruling at 7.
[26] Exh. CCA-01 at 10:3-5.
[27] *Id*. at 10:5-9.
[28] *Id*. at 10:9-13.

This is necessary to allow parties sufficient time to develop and analyze proposals, conduct discovery, and ensure consistency among all three IOUs.

D. The Commission Does Not Need to Require Additional Reporting with Regard to FGC

Scoping Item 2 seeks party feedback as to whether the Commission should require the IOUs to report shifts in FGC categories more frequently than they already do.[29] This additional reporting requirement is not necessary at this time, as the IOUs currently include FGC in general rate cases and ERRA proceedings in which the Commission reviews and approves generation-related costs.[30]

Should the Commission determine that additional reporting is necessary at this time, the Commission could develop a template for the IOUs to periodically report FGC and how they are recovered from customers.[31] This template could include specific categories of information the Commission deems necessary, and could be submitted annually as part of the ERRA proceedings.[32] If the Commission adopts additional reporting requirements, all IOUs should follow the same process and utilize the same reporting tools to allow for greater efficiency and more direct comparison across categories.

II. THE COMMISSION SHOULD EVALUATE THE IOUS' COMMON COST ALLOCATION PRACTICES IN A NON-EXPEDITED PROCEEDING IN WHICH ALL IOUS ARE PARTIES

In its (Track 2 PHCS), PG&E proposed a new methodology to allocate its Common Costs.[33] PG&E's Common Costs are costs related to its procurement activities and include Energy Supply Administration (ESA) costs, as well as carrying costs related to collateral requirements and

---

29 Scoping Ruling at 7.
30 Exh. CCA-01 at 11:7-9.
31 *Id*. at 11:11-12.
32 *Id*. at 11:12-16.
33 PG&E Prehearing Conference Statement at 3-6.

greenhouse gas (GHG) emissions compliance instruments (collateral costs).[34] While each IOU incurs analogous costs, the Commission determined that changes to PG&E's Common Cost allocation methodology were outside the scope of this proceeding as PG&E was the only IOU to suggest a change to the allocation of its Common Costs.[35]

Subsequently, however, both PG&E and SDG&E proposed changes to the allocation of their Common Costs in their respective 2025 ERRA Forecast proceedings.[36] PG&E claimed it was seeking to align its methodology with SCE, [37] and SDG&E claimed it was following PG&E's lead.[38] But the Administrative Law Judge (ALJ) in SCE's 2025 ERRA Forecast proceeding excluded Common Cost allocation from the scope of that proceeding.[39] As a result, Common Cost allocation was litigated in parallel in two out of the three IOU's ERRA Forecast proceedings last year. And because PG&E's and SDG&E's proposals were litigated in ERRA Forecast proceedings, and not in a rulemaking, the Commission did not have an opportunity to comprehensively compare and contrast the IOUs' Common Cost allocation practices.

In its Final Decisions in PG&E and SDG&E's 2025 ERRA Forecast proceedings, the Commission nevertheless attempted to achieve consistency to the greatest degree possible by approving allocation methodologies that aligned more closely with SCE's current Common Cost allocation methodology.[40] However, the Commission characterized that outcome as a solution for "this year's ERRA," and reasoned that proposals to refine Common Cost allocation "can be more

---

34 *Id*. at 3; *see also* D.24-12-038 at 30.

35 Scoping Ruling at 6 ("We also believe the specific items SDG&E and PG&E raised in their PHC statements, as discussed above, would be better addressed in separate proceedings, because each utility's requests raised in their PHC filings were not directly responses to the August 1, 2023, ALJ rulings, and the issues may not align across utilities").

36 *See* Exh. CCA-01 at 8:14-19. Note that PG&E modified its Common Cost Allocation proposal through rebuttal testimony in an attempt to align more closely with SCE's methodology.

37 *See* D.24-12-038 at 31-32.

38 *See* Exh. CCA-01 at 8:14-19.

39 *Assigned Commissioner's Scoping Memo and Ruling*, at 2-3, A.24-05-007, (Aug. 14, 2024).

40 D.24-12-038 at 32, 37; D.24-12-040 at 33-34.

thoroughly examined and any resulting directives can be made applicable to the three major IOUs uniformly" in a "separate proceeding involving the three major IOUs."[41]

The Commission should therefore revisit this issue in a non-expedited proceeding in which all IOUs are parties to allow for the time, processes, and direct comparison needed to develop a long-term solution that can be applied consistently across each utility. Typically, the policymaking necessary to modify established Commission methodologies does not occur in individual ERRA Forecast proceedings. This makes sense, as the expedited and individual nature of the typical ERRA Forecast proceedings provides neither the time nor the opportunity for direct comparison necessary to establish new methodologies applicable across IOU service territories. A non-expedited proceeding with all IOUs present will provide the Commission with the opportunity to more efficiently and thoroughly develop the record on this issue.

III. CONCLUSION

For the foregoing reasons, the CCA Parties respectfully request that the Commission adopt the recommendations set forth in the Summary of Recommendations above.

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 for the California Community Choice Association

/s/ Alissa Greenwald
Alissa Greenwald
Tim Lindl
KEYES & FOX LLP
1580 Lincoln St., Suite 1105
Denver, CO 80203
Telephone: (913) 302-5567
E-mail:agreenwald@keyesfox.com
tlindl@keyesfox.com

Counsel for San Diego Community Power and Clean Energy Alliance

Date: February 3, 2025

41 D.24-12-040 at 33-34.

ADVICE LETTER (AL) SUSPENSION NOTICE
ENERGY DIVISION

Utility Name: PG&E	Date Utility Notified: 2/12/25
Utility Number/Type: U	E-Mailed to: PGETariffs@pge.com
Advice Letter Number(s): 7486-E	ED Staff Contact: Asal Esfahani
Date AL(s) Filed: 1/16/2025	ED Staff Email: ae3@cpuc.ca.gov
Utility Contact Person: Sidney Bob Dietz II	ED Staff Phone No.: 415-703-2409
Utility Phone No.: n/a	

☒ **SUSPENSION (up to 120 DAYS from the expiration of the initial review period)**

This is to notify that the above-indicated AL is suspended for up to 120 days **beginning February 17, 2025** (30 days after the Advice Letter filing) for the following reason(s) below. If the AL requires a Commission resolution and the Commission's deliberation on the resolution prepared by Energy Division extends beyond the expiration of the initial suspension period, the advice letter will be automatically suspended for up to 180 days beyond the initial suspension period.

☐A Commission Resolution is Required to Dispose of the Advice Letter

☐ Advice Letter Requests a Commission Order

☒ Advice Letter Requires Staff Review

The expected duration of initial suspension period is 120 days

☐ **FURTHER SUSPENSION (up to 180 DAYS beyond initial suspension period)**

The AL may require a Commission resolution and the Commission's deliberation on the resolution prepared by Energy Division has extended beyond the expiration of the initial suspension period. The advice letter is suspended for up to 180 days beyond the initial suspension period.

If you have any questions regarding this matter, please contact Asal Esfahani at ae3@cpuc.ca.gov.

cc:
EDTariffUnit
Maryam Mozafari, Supervisor, Demand Response
Wade Stano, Senior Policy Council, MCE

* Note: reference – Decision D.02-02-049, dated February 21, 2002, and Rule 7.5 in appendix A of D.O7-01-024

Comments on Feb 5 working group kick-off meeting

Initiative: Demand and Distributed Energy Market Integration

Comment period

Feb 05, 2025, 04:00 pm - Feb 21, 2025, 05:00 pm

Submitting organizations

California Community Choice Association

California Community Choice Association

Submitted on 02/21/2025, 01:27 pm

Contact

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

1. Please provide your organization's feedback on the guiding Principles presented in the February 5th working group session; Efficiency, Competition, Feasibility, Simplicity, Reliability/Compliance, and Jurisdictional Roles and Responsibilities. Do these appropriately align with your organization's perspective?

The California Community Choice Association (CalCCA) appreciates the opportunity to comment on the California Independent System Operator's (CAISO) initial meeting of the Demand and Distributed Energy Market Integration working group. These guiding principles align with CalCCA's perspective on market design.

2. In addition to the 2024 Catalog requests received, please provide your organization's proposed problem(s) or issue(s) to be addressed for potential scoping moving forward.

Links to 2024 Annual policy initiatives roadmap process: https://stakeholdercenter.caiso.com/RecurringStakeholderProcesses/Annual-policy-initiatives-roadmap-process-2024Appendix B: https://stakeholdercenter.caiso.com/InitiativeDocuments/2024-Final-Policy-Initiatives-Roadmap-and-Disposition.pdf

CalCCA's primary interests in this stakeholder initiative are: (1) ensuring community choice aggregators' (CCA) distributed energy resources (DER) receive full resource adequacy (RA) credit and energy market rents for participation in the wholesale market; and (2) establishing the appropriate level of DER visibility to the CAISO as soon as practicable to facilitate robust DER participation in the wholesale market. The 2024 Catalog requests generally capture the proposed issues that the CAISO should include in the scope of this stakeholder effort. In particular, CalCCA is interested in further exploring the modified Proxy Demand Response (PDR) model from the Joint Demand Response (DR) parties to support RA credit for DER market participation.

3. Would your organization like to utilize this Working Group to provide additional education on current demand and distributed energy market participation?

The CAISO should host an educational session on its existing DR and DER market participation models to help newer market participants learn about pathways for market participation and related RA issues. CalCCA proposes the following topics be addressed in this session:

- Differences between supply-side and load-modifying participation pathways;
- Existing market participation models for DR and DER and if/how those participation models receive RA credit; and
- California Public Utilities Commission and CAISO jurisdictional responsibilities and rules for obtaining RA credit.

4. What topic(s) would your organization be interested in presenting? What is the problem/issue seeking to be addressed, and what is the value in resolving it? Which stakeholders would it impact?

CalCCA has no particular topics to be presented at this time but may be interested in presenting on issues as the initiative progresses.

ADVICE LETTER SUMMARY

ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No.: Marin Clean Energy (MCE)

Utility type:

☑ ELC ☐ GAS ☐ WATER

☐ PLC ☐ HEAT

Contact Person: Jordyn Bishop
Phone #: (925) 378-6753
E-mail: jbishop@mceCleanEnergy.org
E-mail Disposition Notice to: jbishop@mceCleanEnergy.org

EXPLANATION OF UTILITY TYPE

ELC = Electric GAS = Gas WATER = Water
PLC = Pipeline HEAT = Heat

(Date Submitted / Received Stamp by CPUC)

Advice Letter (AL) #: 85-E

Tier Designation: 1

Subject of AL: MARIN CLEAN ENERGY'S NOTICE OF INTENT TO ENROLL CUSTOMERS IN PACIFIC GAS AND ELECTRIC COMPANY'S AGRICULTURAL PILOT AND EXPANDED PILOT 2 PURSUANT TO DECISION 24-01-032

Keywords (choose from CPUC listing):

AL Type: ☐ Monthly ☐ Quarterly ☐ Annual ☑ One-Time ☐ Other:

If AL submitted in compliance with a Commission order, indicate relevant Decision/Resolution #:

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL: N/A

Summarize differences between the AL and the prior withdrawn or rejected AL: N/A

Confidential treatment requested? ☐ Yes ☑ No

If yes, specification of confidential information:
Confidential information will be made available to appropriate parties who execute a nondisclosure agreement. Name and contact information to request nondisclosure agreement/ access to confidential information:

Resolution required? ☐ Yes ☑ No

Requested effective date: 2/28/25

No. of tariff sheets: N/A

Estimated system annual revenue effect (%): N/A

Estimated system average rate effect (%): N/A

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: N/A

Service affected and changes proposed[1]: N/A

Pending advice letters that revise the same tariff sheets: N/A

[1]Discuss in AL if more space is needed.

Clear Form

Protests and correspondence regarding this AL are to be sent via email and are due no later than 20 days after the date of this submittal, unless otherwise authorized by the Commission, and shall be sent to:

California Public Utilities Commission Energy Division Tariff Unit Email: EDTariffUnit@cpuc.ca.gov	Contact Name: Jordyn Bishop Title: Senior Policy Analyst Utility/Entity Name: Marin Clean Energy Telephone (xxx) xxx-xxxx: (925) 378-6753 Facsimile (xxx) xxx-xxxx: Email: jbishop@mceCleanEnergy.org
	Contact Name: Title: Utility/Entity Name: Telephone (xxx) xxx-xxxx: Facsimile (xxx) xxx-xxxx: Email:

CPUC
Energy Division Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102

Clear Form

ENERGY Advice Letter Keywords

Affiliate	Direct Access	Preliminary Statement
Agreements	Disconnect Service	Procurement
Agriculture	ECAC / Energy Cost Adjustment	Qualifying Facility
Avoided Cost	EOR / Enhanced Oil Recovery	Rebates
Balancing Account	Energy Charge	Refunds
Baseline	Energy Efficiency	Reliability
Bilingual	Establish Service	Re-MAT/Bio-MAT
Billings	Expand Service Area	Revenue Allocation
Bioenergy	Forms	Rule 21
Brokerage Fees	Franchise Fee / User Tax	Rules
CARE	G.O. 131-D	Section 851
CPUC Reimbursement Fee	GRC / General Rate Case	Self Generation
Capacity	Hazardous Waste	Service Area Map
Cogeneration	Increase Rates	Service Outage
Compliance	Interruptible Service	Solar
Conditions of Service	Interutility Transportation	Standby Service
Connection	LIEE / Low-Income Energy Efficiency	Storage
Conservation	LIRA / Low-Income Ratepayer Assistance	Street Lights
Consolidate Tariffs	Late Payment Charge	Surcharges
Contracts	Line Extensions	Tariffs
Core	Memorandum Account	Taxes
Credit	Metered Energy Efficiency	Text Changes
Curtailable Service	Metering	Transformer
Customer Charge	Mobile Home Parks	Transition Cost
Customer Owned Generation	Name Change	Transmission Lines
Decrease Rates	Non-Core	Transportation Electrification
Demand Charge	Non-firm Service Contracts	Transportation Rates
Demand Side Fund	Nuclear	Undergrounding
Demand Side Management	Oil Pipelines	Voltage Discount
Demand Side Response	PBR / Performance Based Ratemaking	Wind Power
Deposits	Portfolio	Withdrawal of Service
Depreciation	Power Lines	

Clear Form

February 28, 2025

California Public Utilities Commission
Energy Division
Attention: Tariff Unit
505 Van Ness Avenue, 4th Floor
San Francisco, CA 94102-3298

MCE Advice Letter 85-E

RE: MARIN CLEAN ENERGY'S NOTICE OF INTENT TO ENROLL CUSTOMERS IN PACIFIC GAS AND ELECTRIC COMPANY'S AGRICULTURAL PILOT AND EXPANDED PILOT 2 PURSUANT TO DECISION 24-01-032

Pursuant to California Public Utilities Commission ("CPUC" or "Commission") Decision ("D.") 24-01-032, Marin Clean Energy ("MCE") hereby submits this Tier 1 Advice Letter ("AL") to notify the Commission of MCE's intent to commence enrollment in the Pacific Gas and Electric Company ("PG&E") Ag Pilot and Expanded Pilot 2, subject to approval by MCE's Board of Directors ("Board").

I. TIER DESIGNATION

This AL has a Tier 1 designation pursuant to D.24-01-032, Conclusion of Law 30.

II. EFFECTIVE DATE

Pursuant to General Order 96-B, MCE requests that this Tier 1 AL become effective on February 28, 2025, the date of submittal.

III. BACKGROUND

On January 26, 2024, the Commission issued D.24-01-032 ("Decision") in the *Order Instituting Rulemaking to Advance Demand Flexibility Through Electric Rate*s, ("R.") 22-07-005. In the Decision, the Commission directed PG&E to expand the Valley Clean Energy ("VCE") Agricultural Real Time Pricing Pilot ("VCE Ag Fit Pilot") authorized in D.21-12-015 to agricultural customers throughout PG&E's service territory ("PG&E Ag Pilot"). The Commission further directed PG&E to expand the pilot to customers in PG&E's service territory on certain residential, commercial, and industrial rates ("Expanded Pilot 2").[1] The Commission also concluded that any CCA in PG&E's service territory may file a Tier 1 advice letter by March 1, 2025, to notify the Commission that it will commence enrollment in the PG&E Ag Pilot or the PG&E Expanded Pilot 2 by June 1, 2025.[2]

[1] D.24-01-032 at 2.
[2] D.24-01-032 at 80.

IV. PURPOSE

In accordance with D.24-01-032, MCE hereby submits this Tier 1 AL to notify the Commission of its intent to commence enrollment, subject to approval by MCE's Board, in the PG&E Ag Pilot and Expanded Pilot 2.

V. NOTICE

A copy of this AL is being served on the official Commission service lists for R.22-07-005.

For changes to these service lists, please contact the Commission's Process Office at (415) 703-2021 or by electronic mail at Process_Office@cpuc.ca.gov.

VI. PROTESTS

Anyone wishing to protest this advice filing may do so electronically by e-mail, which must be received no later than 20 days after the date of this advice filing. Protests should be emailed to:

CPUC, Energy Division
Attention: Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102
Email: EDTariffUnit@cpuc.ca.gov

In addition, protests and all other correspondence regarding this AL should also be sent electronically to the attention of:

Jordyn Bishop
Senior Policy Analyst
MARIN CLEAN ENERGY
Email: jbishop@mceCleanEnergy.org

There are no restrictions on who may submit a protest, but the protest shall set forth specifically the grounds upon which it is based and shall be submitted expeditiously.

VII. CORRESPONDENCE

For questions, please contact Jordyn Bishop at (925) 378-6753 or by electronic mail at jbishop@mceCleanEnergy.org.

/s/ Jordyn Bishop

Jordyn Bishop
Senior Policy Analyst
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (925) 378-6753
Email: jbishop@mceCleanEnergy.org.

cc: Service List for R.22-07-005.

MARCH FILINGS

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	R.23-10-011

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING COMMENTS ON THE ASSIGNED COMMISSIONER'S AMENDED SCOPING MEMO AND RULING

Leanne Bober,
Director of Regulatory Affairs and
Deputy General Counsel
Lauren Carr,
Senior Market Policy Analyst
Eric Little,
Director of Market Design

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

March 3, 2025

TABLE OF CONTENTS

Table of Contents continued

Table of Contents continued

SUMMARY OF RECOMMENDATIONS

CalCCA recommends that the Commission:[1]

- Adopt Energy Division's updated system RA waiver proposal, with two additions: (1) a process to allow parties to qualify for a waiver under a rebuttable presumption process to enhance efficiency and limit administrative burden; and (2) remove any sunset date on the waiver process.;

- Allow LSEs to cure deficiencies by T-1 to increase ability to increase opportunities to procure available RA and encourage continued procurement efforts;

- Adopt hourly load obligation trading, to promote RA transactability and affordability, with an initial limit of 25 percent of a LSE's compliance obligation;

- Work with the CAISO to develop the systems and processes needed to unlock the reliability value of EO co-located resources;

- Continue to develop and implement an UCAP counting methodology to better incent RA resource maintenance and availability;

- Reject SCE's proposal to reconsider the local RA CPE timeline modification so that LSEs have certainty of their CPE allocations when conducting their procurement;

- Ensure SCE's requested clarification of the CPE net requirement retains LSEs' ability to sell to the CPE;

- Utilize the RA filing process to collect the local RA data for the local RA CPE data request process to promote efficiency and limit administrative burden;

- Eliminate MTR bridge costs in non-summer months for all eligible bridge capacity to promote affordability without negatively impacting reliability;

- Address CAISO tariff changes related to RA resource RUC bidding to align with changes in the EDAM initiative;

- Adopt the Joint DR Parties' proposal to provide DR resources with a QC value outside of the AAH so that DR resources can be shown consistent with their demonstrated capability; and

- Scope into future RA proceedings counting and charging sufficiency of LDES.

---

[1] Acronyms used in the Summary of Recommendations are defined in the body of this document, *California Community Choice Association's Opening Comments on Assigned Commissioner's Amended Scoping Memo and Ruling*, dated March 3, 2025.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	R.23-10-011

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING COMMENTS ON THE ASSIGNED COMMISSIONER'S AMENDED SCOPING MEMO AND RULING

California Community Choice Association[2] (CalCCA) submits these opening comments pursuant to the *Assigned Commissioner's Amended Scoping Memo and Ruling*[3] (Ruling), dated November 1, 2024. The Ruling amends the previous Scoping Memo[4] issued in this proceeding on December 18, 2023, to designate issues as Track 3 and to set a schedule for Track 3. Except as expressly set forth in the Ruling, the terms of the previously issued Scoping Memo remain unchanged. CalCCA also responds to the *Administrative Law Judge's Ruling on Energy Division's Hour Offset Workshop Slides and Load Migration Update*[5] (February 25 Ruling), dated February 25,

---

[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 Amended Scoping Memo and Ruling*, Rulemaking (R.) 23-10-011 (Nov. 1, 2024): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M544/K652/544652400.PDF.

[4] *Assigned Commissioner's Scoping Memo and Ruling*, R.23-10-011 (Dec. 18, 2023) (Scoping Memo): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M521/K589/521589385.PDF.

[5] *Administrative Law Judge's Ruling on Energy Division's Hour Offset Workshop Slides and Load Migration Update*, R.23-10-011 (Feb. 25, 2025): https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=557607541.

2025, which provides updated Energy Division Track 3 proposal analysis and allows parties to incorporate comments on that analysis in these Ruling opening comments.

I. INTRODUCTION

CalCCA appreciates the opportunity to comment on the thoughtful Track 3 proposals from Energy Division and parties. In these comments, CalCCA continues to advocate for the Commission's adoption of CalCCA's proposals submitted on January 17, 2025.[6] CalCCA also offers clarifications and additional support for its proposals in response to the comments and questions it received at the February 12-13, 2025, workshops. In addition, CalCCA comments on Energy Division's and other parties' proposals, focusing on promoting resource adequacy (RA) affordability and transactability, accurately accounting for resources' reliability contribution, and aligning Commission and California Independent System Operator (CAISO) RA processes.

In summary, CalCCA recommends that the California Public Utilities Commission (Commission):

- Adopt Energy Division's updated system RA waiver proposal, with two additions: (1) a process to allow parties to qualify for a waiver under a rebuttable presumption process to enhance efficiency and limit administrative burden; and (2) remove any sunset date on the waiver process;

- Allow load-serving entities (LSE) to cure deficiencies by T-1[7] to increase ability to increase opportunities to procure available RA and encourage continued procurement efforts;

- Adopt hourly load obligation trading, to promote RA transactability and affordability, with an initial limit of 25 percent of a LSE's compliance obligation;

- Work with the CAISO to develop the systems and processes needed to unlock the reliability value of energy-only (EO) co-located resources;

---

6 References herein to party proposals refer to those submitted on or about January 17, 2025, in R.23-10-011.

7 "T" refers to the start of the compliance month.

- Continue to develop and implement an unforced capacity (UCAP) counting methodology to better incent RA resource maintenance and availability;

- Reject Southern California Edison Company's (SCE) proposal to reconsider the local RA central procurement entity (CPE) timeline modification so that LSEs have certainty of their CPE allocations when conducting their procurement;

- Ensure SCE's requested clarification of the CPE net requirement retains LSEs' ability to sell to the CPE;

- Utilize the RA filing process to collect the local RA data for the local RA CPE data request process to promote efficiency and limit administrative burden;

- Eliminate mid-term reliability (MTR) bridge costs in non-summer months for all eligible bridge capacity to promote affordability without negatively impacting reliability;

- Address CAISO tariff changes related to RA resource residual unit commitment (RUC) bidding to align with changes in the Extended Day-Ahead Market (EDAM) initiative;

- Adopt OhmConnect, Inc. and Leapfrog Power, Inc.'s (the Joint DR Parties) proposal to provide demand response (DR) resources with a qualifying capacity (QC) value outside of the availability assessment hours (AAH) so that DR resources can be shown consistent with their demonstrated capability; and

- Scope into future RA proceedings counting and charging sufficiency of long-duration energy storage (LDES).

II. ENERGY DIVISION'S UPDATED SYSTEM RA WAIVER PROPOSAL SHOULD BE ADOPTED WITH MODIFICATIONS, INCLUDING A REBUTTABLE PRESUMPTION PROCESS TO ENHANCE EFFICIENCY AND LIMIT ADMINISTRATIVE BURDEN

The Commission should adopt Energy Division's proposed system RA waiver process, with the clarifications and modifications described herein. CalCCA agrees with Energy Division's assessment that increases to the Planning Reserve Margin (PRM) at this time could exacerbate market tightness, high prices, and the potential to exert market power, and a system RA waiver offers an effective price mitigation tool. The Commission should therefore: (1) adopt Energy Division's updated system RA waiver proposal clarified in the February 25 Ruling; (2) remove any sunset of the system RA waiver; (3) adopt a rebuttable presumption process to increase efficiency and limit administrative burden for Energy Division and LSEs; (4) clarify that waivers will relieve LSEs of financial penalties, points accumulation, expansion limitations, and strategic reserve payments; and (5) clarify that the system RA waiver applies to year-ahead and month-ahead showings for summer months.

A. The Commission Should Adopt Energy Division's Updated System RA Waiver Proposal

The Commission should adopt Energy Division's updated system RA waiver proposal to promote RA affordability by mitigating excessively high RA prices and avoid penalizing LSEs for deficiencies that they could not have remedied at reasonable prices. CalCCA agrees with Energy Division that "[a]dopting a PRM that is higher than the current [compliance year] 2025 17 [percent] PRM could potentially exacerbate market tightness, increase market power dynamics, and impact RA prices."[8] A system RA waiver process provided to LSEs that demonstrate commercially reasonable efforts to procure up to a certain price threshold will provide much-needed relief to LSEs and their customers who have been paying excessively high RA costs over the last several years.

On January 17, 2025, Energy Division proposed the following temporary system RA waiver process:

- Adopt a 21 percent PRM for the months of October to March, and a 22.5 percent PRM for the months of June to September;
- Allows LSEs to request temporary system waivers in peak months (June – Sept.) for RA requirements above 17 percent if certain criteria are met; and
- CAISO backstops RA deficiencies with costs allocated to LSEs with deficiencies.[9]

The February 25 Ruling includes Energy Division's modifications to the recommended PRMs resulting from correcting the hour offset error presented during the February 12, 2025,

8 Energy Division Proposal, at 11.
9 *Id.,* at 15.

workshop.[10] The Ruling includes an updated system waiver proposal modifying the PRM to 21 percent in June through October, and 20 percent in all other months.[11] CalCCA greatly appreciates Energy Division's prompt response to the identification of the hour offset error, and supports the clarifications made in the February 25 Ruling to the system RA waiver proposal.

B. The Commission Should Not Sunset the System RA Waiver Process

The Commission should reject Energy Division's proposal to sunset the system waiver process after 2027.[12] Energy Division has demonstrated current market conditions necessitate a waiver. If market conditions return to competitive levels, it is unlikely an LSE will qualify for a waiver, so the number of waiver requests the Commission receives and the administrative burden of processing such a requirement will likely decline. However, if unforeseen circumstances exist or tight market conditions return, the Commission should continue to have the ability to evaluate system RA compliance with the waiver process in place as it has for local RA.

C. The Commission Should Adopt a Rebuttable Presumption Process to Enhance Efficiency and Limit Administrative Burden

The Commission should allow LSEs to seek a system RA waiver through meeting clear and robust criteria resulting in a rebuttable presumption that a waiver should be granted. This rebuttable presumption process can enhance efficiency and limit the administrative burden on both LSEs and Energy Division. Energy Division's proposal states that the process for requesting a system waiver could follow the existing local waiver process in which LSEs submit requests via a Tier 2 advice letter. Energy Division recognizes that reaching resolution on waiver requests under the existing local waiver process may create additional administrative burden, as well as take a significant

---

10 *See* February 25, Ruling, Attachment 2: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M557/K609/557609748.PDF.

11 *Ibid.*

12 *See* Energy Division Proposal, at 16.

amount of time. Therefore, Energy Division proposes that the process for requesting a system waiver could follow an alternative process, such as an Energy Division letter, and asks for party input on the preferred process.[13]

To limit administrative burden and increase the timeliness of system waiver request processing, LSEs should have the option to complete a standardized template with an officer attestation submitted to Energy Division to claim a rebuttable presumption that a waiver should be granted. This rebuttable presumption process will be in addition to the standard waiver process (which requires the LSE to provide proof of the circumstances warranting a waiver (which may not otherwise qualify for the rebuttable presumption process)). The standardized template could include clear and robust criteria met by the LSE that automatically equates to a presumption that the LSE's waiver be approved. While the presumption will have been met, Energy Division will still have the opportunity to rebut the presumption if it doubts whether the waiver should be granted.

CalCCA proposes that the standardized form include boxes to check next to the following criteria for an LSE to qualify for the rebuttable presumption – that the LSE:

1. Issued a request for offer (RFO);
2. Solicited bids, including participation in at least one other market participants' (including investor-owned utilities, community choice aggregators (CCA), or electric service providers (ESP)) RFO(s) offering RA needed by the LSE in the relevant time period;
3. Pursued other means of bilaterally procuring capacity, including utilizing broker markets or direct bilateral negotiations;
4. Continued procurement activities after reaching its 17 percent PRM requirement up to a timeframe that would reasonably result in a confirm by the RA showing deadline; AND
5. Despite having actively pursued all commercially reasonable efforts to procure, received:

---

13 *See* Energy Division Proposal, at 17.

a) No bids;

b) Insufficient bid volumes relative to the LSE's RA requirement below the Commission's defined price threshold to meet its portion of the PRM requirement that is eligible for a waiver; OR

c) Received bids with one or more of the following unreasonable terms and/or conditions:

   i) An offer for a strip with a price below the price threshold in only a subset of months; OR

   ii) An offer for a 12-month strip or longer to meet a one-month need.

In addition, Energy Division should approve additional terms and conditions to add to section 5.c., above, based upon experience evaluating waivers. The template should also include a field for LSEs to provide a description of supporting information it has to support the rebuttable presumption or other relevant information if the LSE believes it can inform the Commission in the event the Commission seeks to rebut the presumption of a waiver. Should the Commission seek to rebut the presumption of a waiver, the Commission should be required to provide a statement of reasons supporting the rebuttal.

The rebuttable presumption process can provide Energy Division a method to quickly process waiver requests for LSEs that meet clear and robust standards proving the elements needed to qualify for a waiver have been met. This process can also provide LSEs with more timely notice of whether they meet the Commission's standards for procurement of RA and allow them to adjust their procurement prior to future showings to align with the Commission's standards. The Commission should target 30 days for processing a waiver request under the rebuttable presumption process so that LSEs know if the waiver is granted by the time their next month-ahead showing is due.

D. The Commission Should Clarify that Waivers will Relieve LSEs of Financial Penalties, Points Accumulation, Expansion Limitations, and Strategic Reserve Payments

The Commission should clarify that waivers will relieve LSEs of all types of Commission-issued RA deficiency penalties, including financial penalties, points accumulation, expansion limitations, or strategic reserve payments. All LSEs are subject to three types of penalties for RA deficiencies: (1) dollar per megawatts (MW) financial penalties; (2) the accumulation of points, in which more points result in higher dollar per MW financial penalties; and (3) strategic reserve payment allocations if the strategic reserve is triggered CCAs and ESPs are also subject to a fourth type of penalty for RA deficiencies: prohibitions on expansion. Energy Division's proposal does not explicitly state that its acceptance of a waiver will relieve an LSE of all four of these penalties. To ensure the system waiver process meets its intended objective of RA price mitigation, the Commission should clarify that granted waivers will relieve LSEs of all four types of Commission-issued penalties.

E. The Commission Should Clarify that the System RA Waiver Applies to Year -Ahead and Month-Ahead Showings for Summer Months

The Commission should clarify that system RA waivers will apply to June through September month-ahead showings and year-ahead showings. Energy Division's proposal is clear that LSEs will be able to request waivers for the peak months of June through September.[14] LSEs make showings for June through September in both the year-ahead and month-ahead timeframe and should be able to request waivers for both year-ahead and month-ahead peak month showings. To apply waivers to year-ahead showings, in which the obligation is only 90 percent, the Commission should clarify that LSEs will be eligible for a waiver of RA requirements above 90 percent of its 117 percent requirement.

---

[14] *See* Energy Division Proposal, at 15.

III. THE COMMISSION SHOULD ALLOW LSES TO CURE DEFICIENCIES BY T-1

In addition to Energy Division's proposals and CalCCA's recommended additions and modifications described above, the Commission should allow LSEs to cure through T-1. Upon such a cure, the Commission should find the LSE compliant and dismiss the waiver request. LSEs must show RA Plans to the Commission to demonstrate compliance with their year-ahead RA (YARA) requirements and month-ahead RA (MARA) requirements. LSEs must make their YARA Plan showings on October 31st prior to the start of the compliance year.[15] LSEs must make their MARA Plan showings 45 days prior to the compliance month. If, on October 31st or 45 days prior to the compliance month, an LSE's showing is deficient, the LSE has a short opportunity to cure its deficiency before the Commission assesses penalties.[16] Because of this timing, new resources that reach commercial operation dates (CODs), or procurement that results in a confirm with an existing resource between T-30 and the compliance month, are not accounted for in Energy Division's assessment of penalties.

In Decision (D.) 24-06-004, the Commission allowed, on an interim basis, new resources with a COD after T-30 and before the start of a summer RA compliance month (T-1) to count towards that compliance month's RA compliance.[17] This interim change aims to increase the number of resources LSEs can count towards RA obligations in light of significant project delays and increase the number of resources with a must-offer obligation to the CAISO markets to enhance grid

---

15 Pursuant to Rule 1.15 of the Commission's Rules of Practices and Procedure, if the due date falls on a Saturday, Sunday, or holiday, it is extended to the following business day.

16 *See 2025 Resource Adequacy and Slice of Day Guide* (Sept. 25, 2024), at 70-71: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/guides-and-resources/2025-ra-slice-of-day-filing-guide.pdf.

17 *See* D.24-06-004, *Decision Adopting Local Capacity Obligations for 2025-2027, Flexible Capacity Obligations for 2025, and Program Refinements*, R.23-10-011 (June 26, 2204), at 32-33: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M534/K619/534619523.PDF.

reliability.[18] The Commission should extend this interim change permanently, and allow LSEs to show new *or existing* resources that become available between T-30 and T-1 to count towards RA showings. Should an LSE reduce its open position between T-30 and T-1, the Commission should not assess penalties on the portion of the deficiency that was cured. If the LSE fully closes its open position, the Commission should dismiss the LSE's waiver request and deem the LSE compliant.

IV. HOURLY LOAD OBLIGATION TRADING SHOULD BE ADOPTED

The Commission should adopt CalCCA's proposal to allow LSEs to transact load obligations on an hourly basis under slice-of-day (SOD) for the reasons described in CalCCA's Proposal.[19] In response to questions and comments received on this proposal during the February 12, 2025, workshop, CalCCA recommends that the Commission: (1) initially implement hourly load obligation trading with a 25 percent limit on how much load each LSE can trade to address any concerns about LSEs trading away their entire obligation or engaging in a number of trades that are administratively burdensome for Energy Division to track and validate; (2) treat defaults on hourly load obligation trades no differently than defaults on RA agreements; and (3) reject parties' assertions that hourly load obligation trading is unnecessary.

A. The Commission Can Initially Limit the Quantity of LSE Hourly Load Obligation Trading to Address Concerns Regarding Trading Away Obligations or the Administrative Burden on Energy Division

If the Commission has concerns about LSEs trading away their entire obligation or that the quantity of trades may be administratively burdensome for Energy Division, the Commission can set an initial trading limit of no more than 25 percent of an LSE's compliance obligation. CalCCA's original proposal did not propose a limit because hourly load obligation trading simply enables

---

18 *See Id.* at 32.

19 *See* CalCCA Proposal, at 3-18: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M553/K679/553679242.PDF.

another procurement product for LSEs with open positions to use to comply with their RA obligation. Market participants should be able to utilize all available procurement mechanisms to meet their needs in the most cost-effective manner.

In the February 12, 2025, workshop, Energy Division and Pacific Gas and Electric Company (PG&E) expressed concern over the lack of a limit in CalCCA's proposal. If the Commission allows hourly load obligation trading, but determines such a limit is necessary, the Commission should adopt a limit of 25 percent of the LSE's compliance obligation. Given this limit may prohibit the use of hourly load obligation trading by smaller LSEs, however, the Commission should also adopt a *de minimis* threshold allowing LSEs with RA requirements less than 200 MW to trade up to 50 MW of their obligation. Furthermore, if the Commission is concerned with the administrative burden of multiple layers of load obligation trades, the Commission can require that if an LSE purchases a load obligation trade and then sells it to another LSE, that sale will count towards that LSE's 25 percent limit.

B. In the Event of Default, the Commission Should Treat Load Obligation Trades Identically to Contracts for Resources

In the event an LSE purchasing a load obligation defaults, the Commission should treat the load obligation trade identical to a transaction with a resource. Any default that occurs before a showing will therefore result in the LSE not including the load obligation trade in its RA showings. The LSE with an open position will need to find another LSE or resource with whom to transact to fill its open position. If an RA showing has already occurred, then both parties will need to honor obligations associated with completed RA showings. In addition, other terms and conditions (including default provisions) from the defaulting LSEs' contract should apply equally to both load obligation trading or for the sale of resources.

C. The Commission Should Reject Parties' Assertions that Hourly Load Obligation Trading is Unnecessary

The Commission should reject comments made during the February 12, 2025, workshop that hourly load obligation trading may be unnecessary because of the ability to swap resources and shape storage. While it may be technically feasible for all LSEs to meet their SOD requirements relying only on swaps (i.e., LSEs trading resources at the monthly level rather than hourly), it will likely be extremely difficult for LSEs to line up all the necessary transactions to meet reliability through a bilateral market design. Swaps are more likely to require multiple transactions between multiple LSEs to achieve compliance.

In addition, hourly obligation trades are likely more feasible because they limit contracting risk to only the LSE counterparties. LSEs face different risks associated with purchasing a resource and then selling it to another LSE, which may result in swaps or resource trading being less feasible.

Hourly load obligation trading simply provides another instrument for LSEs to comply with RA requirements. Such trading should be available given LSEs may find it simpler and more affordable than monthly trading of resources. Swaps and full resource procurement should remain options, but they should not be the only options. A properly constructed load obligation trade will allow for the grid to be reliably maintained while buyers and sellers determine amongst themselves the value of the load obligation.

V. THE COMMISSION AND THE CAISO SHOULD WORK TOGETHER TO DEVELOP THE SYSTEMS AND PROCESSES NEEDED TO UNLOCK THE RELIABILITY VALUE OF ENERGY ONLY CO-LOCATED RESOURCES

CalCCA's proposal includes a recommendation for the Commission to reevaluate co-located resource counting methodologies to allow EO co-located resource components to count for RA under SOD as long as all co-located components do not exceed the deliverable MW at the point-of-interconnection.[20] During the February 13, 2025, workshop, Energy Division asked how many MW of RA capacity this proposal could unlock from existing co-located resources. To answer this question, CalCCA reviewed the February 2025 Master Resource Database.[21] This review revealed that 2,035 MW of net dependable capacity are available from 14 solar resources and one battery storage resource, where hourly RA countability is limited by either energy-only or partial deliverability status.[22] In each of these cases, the amount of deliverability at the point of interconnection, when reviewed hourly, could allow for more RA to be shown from those co-located resources.

While other considerations must be made (e.g., must-offer obligation, different off-takers, etc.), the value of 2,035 MW of net dependable capacity with various RA counting in each hour should not be ignored. These resources are already operational and can provide grid reliability. With RA prices at all-time highs, the Commission should proceed with determining how co-located resources can further qualify to provide RA. Opportunities to leverage the reliability value of EO resources will increase in future years, as the 2023-2024 Transmission Planning Process includes a significant amount of EO resources, including 23,311 MW of EO solar in 2035 compared to 15,636 MW of fully deliverable solar.[23] While some of these EO resources could be stand-alone, it is possible that many will co-locate with deliverable storage. For these reasons, the Commission should

---

20 See CalCCA Proposal, at 20-26.

21 *See* https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/slice-of-day-compliance-materials/mrd-final-2025_02172025.xlsx.

22 In the cases of partial deliverability, the maximum amount of partial deliverability was 0.789 MW on a 300 MW solar resource with a 230 MW co-located battery on a 250 MW interconnection limit.

23 *See 2023-2024 Transmission Plan* (May 23, 2024), at 65: https://stakeholdercenter.caiso.com/InitiativeDocuments/BOARDAPPROVED_2023-2024_TransmissionPlan.pdf.

expedite work with stakeholders and the CAISO to identify the necessary rules to unlock this existing capacity.

VI. THE COMMISSION SHOULD CONTINUE TO DEVELOP AND IMPLEMENT A UCAP COUNTING METHODOLOGY

The Commission should continue its work to develop and implement a UCAP counting methodology. Such a methodology has the potential to better incentivize maintaining resources than the status quo, which relies on the RA availability incentive mechanism (RAAIM) and forced outage substitution rules. In developing its UCAP counting methodology, the Commission should: (1) coordinate with CAISO; (2) verify PRM impacts through a loss-of-load expectation (LOLE) study; (3) apply UCAP to all eligible RA resources regardless of whether it was shown for RA during the time of a forced outage; (4) use a supply cushion approach; (5) adopt Energy Division's proposed weighting; (6) minimize impacts to existing contracts; (7) develop a methodology to calculate UCAP for new resources without a class average; and (8) work with stakeholders to better define UCAP-eligible outages for storage resources.

A. The Commission and CAISO Should Work Together to Develop a UCAP Counting Methodology

The Commission should continue to develop a UCAP counting methodology in alignment with the CAISO. The CAISO has an active stakeholder process to evaluate UCAP. Energy Division staff should attend and participate in these meetings and ensure that any future workshops at the Commission happen in concert with the progress at the CAISO. The Commission should continue its efforts to coordinate with the CAISO in this respect.

B. The Commission Should Conduct a LOLE Study to Verify that UCAP Adoption Will Result in an Equal and Opposite Adjustment to the PRM

February 12, 2025, workshop participants appeared to largely agree that since the PRM accounts for forced outages and the resource's net qualifying capacity (NQC) does not, any change to resource counting should be met with an equal and opposite offset in the PRM. Before proceeding further in this effort, the Commission should provide data showing that this equal and opposite effect will materialize in the LOLE study that sets the PRM. If the offset is not equal and opposite, the Commission should begin a dialogue with stakeholders to examine why. A shift to UCAP counting that does not meet this criterion appears flawed and deserving of further consideration to either perfect the UCAP calculation methodology or determine whether it is suitable in California. To validate this, the Commission will need to perform a LOLE analysis. Given the time necessary to perform this calculation and for stakeholders to evaluate the result, the Commission should not implement UCAP any earlier than 2028, as proposed by the California Energy Storage Alliance (CESA).[24]

C. The Commission Should Apply UCAP to All Eligible RA Resources Regardless of Whether it is Shown for RA at the Time of Forced Outage

The Commission should apply UCAP to all resources regardless of whether the resource has been shown for RA at the time of the forced outage. Forced outages largely appear to be beyond the generator's control except for performing regular maintenance. Therefore, not counting an outage based upon the resource not being shown for RA will largely coincide with luck and not with any form of incentive. In addition, the Commission should avoid mechanisms that encourage entities to show only the bare minimum to meet RA requirements. If an LSE has excess capacity, it should be encouraged to show a long RA position to the Commission so that as many resources as possible are required to participate in the CAISO energy and ancillary services markets. With RAAIM, this incentive does not exist as resources would rather not be shown since it would take a financial risk. Similarly, if UCAP is only calculated for resources that are shown, the incentive to show the bare minimum will continue. Finally, if UCAP depends on RA showing status, this will further encourage

[24] CESA Proposal, at 4.

LSEs to hold long positions to substitute for a forced outage. This is common practice in RA under RAAIM and has contributed to heightening RA scarcity. The Commission should develop rules that encourage parties to either show or sell excess RA positions to avoid tight capacity market conditions.

D. The Commission Should Continue to Develop a Supply Cushion to Identify Forced Outages that Apply to a Resource's UCAP

The Commission's proposal to use a supply cushion to identify forced outages that are used to calculate UCAP sets correct incentives. While in any given year, market participants do not know *a priori* which hours will be the most constrained, history predicts that these hours will primarily occur during the peak and net load peak of the summer. This history will give generators proper incentives to perform maintenance before the historically tightest hours. If and when those hours change, they will likely occur slowly, with one or a few hours moving to historically unseen periods. This movement will inform generators of what to expect in coming years and when to prepare their resources for reliable operation.

E. The Commission Should Adopt Energy Division's Proposed Weighting

The Commission should adopt Energy Division's proposal for a weighting of UCAP for resources that is the most recent three years with a weight of 44.45 percent, 33.33 percent, and 22.22 percent for the three-year period from most recent to most distant. This proposal is reasonable and should be adopted. Weighing the most recent year more highly than the others will provide an incentive to perform major maintenance that will significantly impact the ability to provide RA quickly. It will also provide an incentive to perform routine maintenance to avoid having increased forced outages.

F. The Commission Should Minimize Impacts on Existing Contracts

To the extent practical, the Commission should seek to minimize impacts on existing contracts. The Commission should, therefore, seek to use existing terminology as those terms are often used in formulating contracts. The most relevant for this discussion is the NQC. Currently, the NQC is defined as the amount of QC adjusted by the CAISO for deliverability. If the total provision of RA is now dependent on forced outage rates, the NQC should be that amount of QC derated by UCAP. In the alternative, the QC could account for the derate of UCAP, which would be consistent with the treatment of renewable resources whose QC is determined by an exceedance methodology that accounts for both fuel availability and resource outages. Either method is acceptable since RA contracts are generally denominated in NQC and should account for what the LSE can use to satisfy RA requirements.

G. The Commission Should Adopt a Methodology for New Resources Without a Class Average

During the workshop, CalCCA asked how a new resource without an existing class of technology would be assigned a UCAP at commercial operation. The Commission should use a similar technology where available. For example, a new enhanced geothermal resource would use the class average for geothermal. This will likely serve as a reasonable starting point. In addition, if the Commission adopts Energy Division's proposed weighting, the general related class average will be quickly replaced. If no similar technology exists, the Commission should use an aggregate of a general classification. For example, if a new flow battery achieves commercial operation, the Commission should use an aggregate of other storage technologies, which would currently include battery and pumped hydro. Again, this would quickly be replaced by resource-specific outages under the proposed weighting.

H. The Commission Should Work with Stakeholders to Consider UCAP-Eligible Outages for Storage Resources

The UCAP should be developed to account for outages due to equipment failures. Critically, this will need to consider battery storage that is not available because any charging has already been used, and the resource is not available due to its state of charge and not due to equipment failure.[25] The Commission should also work with stakeholders to determine how to address storage resources that are receiving Investment Tax Credits and will only charge from its host renewable resource. In this case, evaluating the reliability of such resources may need to account for outages caused by fuel availability to charge the battery.

VII. SCE'S PROPOSAL TO RECONSIDER THE ADOPTION OF CALCCA'S CPE PROCUREMENT TIMING PROPOSAL SHOULD BE REJECTED

The Commission should reject SCE's proposal to reconsider the adoption of CalCCA's Track 2 proposal to modify the CPE timeline. CalCCA's proposal, which was adopted in D.24-12-003,[26] requires CPEs to make their final showings one year in advance of LSE year-ahead showings, consistent with the 100 percent local RA requirements two years forward. SCE states the Commission should reconsider this proposal because it "increases the risk of either over-procurement and unnecessary costs for customers, or under-procurement, which perpetuates the CPEs' and LSEs' current predicament, and which can also increase customer costs."[27] Contrary to

---

[25] In D.24-12-003, the Commission agreed with CalCCA, stating "[w]e agree with CalCCA that forced outage rates for storage resources should reflect plant failures but not state-of-charge, as the model used in SERVM already accounts for state-of-charge when dispatching storage. A battery resource's state-of-charge is somewhat analogous to onsite fuel storage and somewhat analogous to resources with long start-up times, neither of which are incorporated into UCAP for conventional resources. While a grid resource's interactions with other resources (including a storage resource's ability to be charged and ready when needed) are important to overall reliability, these interactions are modeled separately from the forced outage events outside the control of resource operators, which UCAP is intended to address. The UCAP methodology for battery storage should therefore incorporate forced outages due to equipment failures, but not state-of-charge." (Footnote omitted)

[26] D.24-12-003, *Decision on Track 2 Issues*, R.23-10-011 (Dec. 12, 2024), at 40-45: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M549/K295/549295013.PDF.

[27] SCE Proposal, at 4.

SCE's claims, it is the failure to resolve the timing issues that will actually risk over-procurement or under-procurement. If CPE allocations are allocated well enough in advance, LSEs have time to adjust their procurement plans to account for these allocations, including selling off excess RA if their CPE allocations make them long or procuring additional RA if they still have open positions after receiving the CPE allocations. If, instead, LSEs over- or under-procure because they cannot predict their CPE allocations, they will not be made aware until it is too late to adjust their procurement.

In D.24-12-003, the Commission states that "locking in CPE allocations more than one year in advance – as compared to two months - would be beneficial in that it would give LSEs more time for procurement and to negotiate favorable RA contracts on behalf of customers" and would "increase certainty for LSEs to understand how much system and flexible RA they may need to procure."[28] It adopts the modified timeline beginning with the 2025 showing for the 2027 RA year, on an interim basis to be reevaluated by the end of 2027. The Commission should not reverse its decision on the CPE timeline change before it has been implemented and tested. Instead, the Commission should reject SCE's proposal and implement the modified timeline for the 2027 compliance year and reevaluate it after implementation as required in D.24-12-003.

VIII. SCE'S REQUESTED CLARIFICATION OF THE CPE NET REQUIREMENT MUST RETAIN LSES' ABILITY TO SELL TO THE CPE

The Commission must ensure that in clarifying the local RA CPE data collection process, as SCE proposes, LSEs retain the ability to sell excess RA to the CPE. D.24-12-003 eliminated the non-compensated self-showing option of the local RA CPE framework in favor of an additional data collection process in which Energy Division collects, aggregates, and provides the CPE data from

[28] D.24-12-003, at 43.

LSEs regarding their local RA capacity under contract.[29] SCE proposes that that because D.24-12-003 does not explicitly state that the CPE should use the data to determine its procurement targets, the Commission should "explicitly define the CPE's 'Net Requirement' as the result of the local capacity requirement technical study less the local capacity derived from the data Energy Division collects for each of the CPE's local areas."[30]

CalCCA understands SCE's desire for more clarity around how to use the information collected in the data request process. Adopting SCE's proposal as is, however, could remove LSEs' ability to sell resources to the CPE. This would fundamentally alter the original CPE design that allowed any entity, including LSEs who no longer have local RA obligations, to offer to sell local RA to the CPE with equal opportunity of being procured. SCE's proposal should be modified. The CPE should not automatically reduce its local obligation by all resources contained in the data request. Instead, the Commission could ask LSEs in its data request which local RA capacity under contract they plan to offer to the CPE and only reduce the CPE's procurement target by the amount of local capacity LSEs do not plan to offer to the CPE. Adopting SCE's proposal without modifying it to include a process such as this will eliminate the potential for an LSE to sell a resource to the CPE and thus treat an LSE differently than other sellers to the CPE.

IX. THE RA FILING PROCESS SHOULD BE USED TO COLLECT LOCAL RA DATA FOR THE CPE DATA COLLECTION PROCESS

The Commission should use the RA filing process to collect the data that will be used in the local RA CPE data collection process. D.24-12-003 eliminated the non-compensated self-showing option of the local RA CPE framework in favor of an additional data collection process in which

---

29 *Id.*, at 36-40:

30 SCE Proposal, at 5.

Energy Division collects, aggregates, and provides the CPE data from LSEs regarding their local RA capacity under contract.[31] The Commission also notes in D.24-12-003 that:

> the IRP Resource Data Template [RDT] is already used to collect information on what resources are under contract with LSEs. The Commission requests that parties submit proposals in Track 3 on how to synchronize the existing IRP data collection process with the data requirements adopted here for the CPE framework, in order to minimize duplication and administrative burden on Commission Staff.[32]

In response to this direction, PG&E proposes to "add a new tab to the IRP RDT requiring LSEs to provide the monthly contracted NQC for local RA resources and the resource technology type for the applicable forward years of the local RA compliance period."[33] Alternatively, PG&E recommends that "should the Commission determine that the existing IRP RDT process creates additional administrative burden,...the Commission authorize Energy Division to incorporate a modified template into the annual RA compliance process."[34]

CalCCA appreciates the Commission's objective of minimizing duplication and administrative burden. PG&E's alternative best achieves these objectives for two reasons. ***First***, the timing of data collection will be more predictable and consistent within the existing YARA compliance filing. YARA compliance filings are required by October 31 of each year. The IRP RDTs are filed by LSEs twice annually on June 1 and December 1 of each year as part of LSE IRP procurement progress compliance reporting. However, when an IRP LSE Plan is due this takes the place of the nearest-in-time compliance report and IRP RDTs are submitted along with the LSE plans. The Commission's IRP cycle had been operating at a two-year frequency but is currently operating at a cadence of 3 years. The IRP LSE Plan submission dates have varied since the

---

31 D.24-12-003, at 36-40.
32 *Id.* at 40.
33 PG&E Proposal, at 2.
34 *Id.,* at 3 (footnote omitted).

beginning of the Commission's IRP program, from the second quarter to the fourth quarter, to suit the needs of the IRP planning cycle which has proven to be more fluid than may be suitable for the Commission's RA program. Additionally, some LSEs may finish MTR procurement and compliance reporting as early as June 2028 after which point they would presumably no longer be filling RDTs.

Second, local RA capacity under contract is already part of the same LSE data collection and reporting processes. By incorporating a local RA data collection into the long-established RA reporting process, the Commission will encourage administrative efficiency on the part of the reporting entities. For these reasons, the Commission should retain RA-related data requests within the RA program, absent broader modifications to consolidate filings across the RA and IRP programs.

X. SCE'S PROPOSAL TO ELIMINATE MTR BRIDGE COST FOR NON-SUMMER MONTHS SHOULD BE ADOPTED WITH THE MODIFICATION TO APPLY TO ALL BRIDGE CAPACITY

The Commission should adopt SCE's proposal to eliminate MTR bridge costs for non-summer months. SCE proposes "that the Commission eliminate, for LSEs that have sufficient RA capacity to meet their month-ahead system RA requirements, the requirement to procure imports during non-summer months to bridge their delayed MTR contracts."[35] SCE states that this proposal can reduce costly and unnecessary procurement without compromising reliability because non-summer months are long in RA capacity.[36] CalCCA agrees with SCE that this proposal can promote affordability without negatively impacting affordability. The Commission should adopt SCE's proposal with the modification to eliminate the requirement for LSEs to incur MTR bridge costs *for any eligible bridge capacity, whether in-state or import,* in non-summer months to promote affordability without negatively impacting reliability. While SCE's proposal appears specific to

---

35 SCE Proposal at 2-3.

36 *Ibid.*

import bridge resources, the MTR decision does not limit bridge capacity to imports and LSEs can use in-state resources as bridge capacity. The Commission should therefore apply SCE's proposal for *any* eligible bridge capacity.

XI. SCE'S PROPOSAL TO ADDRESS CAISO TARIFF CHANGES FOR RUC PARTICIPATION SHOULD BE ADOPTED

The Commission should adopt SCE's proposal to address CAISO tariff changes for RUC participation resulting from the Day-Ahead Market Enhancements (DAME) and Extended Day-Ahead Market (EDAM) initiatives. SCE proposes that the Commission reconsider D.05-10-042's requirement for RA resources to "submit a zero dollar ($0) bid for RA capacity bid into RUC and that an RA resource will not be eligible for any RUC availability payment or revenue."[37] CalCCA agrees this revision is necessary because, upon DAME and EDAM implementation, the CAISO will no longer require zero-dollar RUC bids from RA resources or prohibit RA resources from RUC market revenues. As SCE states, if the Commission retains its zero-dollar RUC bidding requirement, LSEs participating in the Commission's RA program could subsidize non-CAISO LSEs in EDAM because the Commission-jurisdictional LSEs' RA resources would likely provide most of the RUC capacity because they would have to bid zero dollars.[38]

The rules adopted in D.05-10-042 were intended to prevent multiple payments for the same capacity, once through RA contracts and again through RUC market revenues.[39] The CAISO addresses this issue by developing transitional measures that will allow LSE/resource pairs to mutually elect for the CAISO to automatically transfer RUC payments to LSEs using functionality

---

37 D.05-10-042, *Opinion on Resource Adequacy Requirements*, R.04-04-003 (Oct. 27, 2005), at 16: https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/50731.PDF.

38 *See* SCE Proposal, at 9.

39 *See* D.05-10-042, at 16.

similar to the functionality used for inter-scheduling coordinator trades.[40] This functionality will be in place for three years to address existing RA contracts that were executed under the RUC bidding rules adopted in D.05-10-042. For these reasons, the Commission should adopt SCE's proposal.

XII. THE JOINT DEMAND RESPONSE PARTIES' PROPOSAL TO PROVIDE DEMAND RESPONSE RESOURCES QUALIFYING CAPACITY VALUES OUTSIDE THE AAH SHOULD BE ADOPTED

The Commission should adopt the Joint DR Parties' proposal to provide DR resources QC values in hours outside the AAH. The Joint DR Parties propose that the Commission should "instruct Energy Division to consider the underlying technologies and load profiles of the resources in a DR provider's portfolio to award QC outside of the AAH during the annual QC awarding process."[41] If the load impact protocols and other supply-side DR QC methodologies demonstrate that a DR program has load reduction capability in hours beyond the AAH, that program should be able to provide RA in those hours under the Commission's SOD program. For this reason, the Commission should adopt the Joint DR Parties' proposal.

XIII. LONG DURATION ENERGY STORAGE COUNTING IN THE SLICE OF DAY PROGRAM REQUIRES FURTHER CONSIDERATION IN A FUTURE RA PROCEEDING

A. Hydrostor's Proposal for a Minimum LDES Procurement Requirement Should be Rejected

The Commission should reject Hydrostor, Inc.'s (Hydrostor) proposal for a minimum LDES procurement requirement within the RA program. Hydrostor proposes that the Commission adopt a "minimum capacity bucket" for LDES "to address the RA SOD framework's current shortcoming in ensuring reliability needs are met by a diverse set of storage resources that include LDES."[42] The

---

40 *See* CAISO, *FERC Approved Tariff Language, Extended Day-Ahead Market and Day-Ahead Market Enhancements Initiative*, Section 11.2.6: https://stakeholdercenter.caiso.com/InitiativeDocuments/FERC-Approved-Tariff-Language-Extended-Day-Ahead-Market-and-Day-Ahead-Market-Enhancements.pdf.

41 Joint DR Parties Proposal, at 2.

42 Hydrostor Proposal, at 5-7.

Commission should reject this proposal. The SOD program is designed to ensure LSEs show resources with sufficient attributes to meet an hourly load forecast plus a PRM, not to ensure LSEs show specific technologies. LSEs can meet their requirements using a variety of different resource portfolios and should continue to have the ability to optimize their own portfolios with technologies that meet their RA requirements in a manner that is most cost-effective and aligned with their individual LSE objectives.

B. Hydrostor's Proposal to Prohibit Multi-Cycles per Day for Storage SOD Showings Should be Rejected

The Commission should reject Hydrostor's proposal to eliminate the ability for storage resources to count for multiple cycles under the SOD framework.[43] The SOD program allows storage resources to be shown for multiple cycles if the resource is capable of cycling multiple times per day. If a storage resource can cycle multiple times per day and demonstrates it has the charging sufficiency to do so, showing for multiple cycles under SOD is consistent with the resource's capabilities. There is no reason storage resources should be prohibited from being shown consistent with their capabilities. Hydrostor's proposal should therefore be rejected.

C. Party Proposals for LDES Accounting and Charging Sufficiency Should be Considered in a Future RA Proceeding

The Commission should consider LDES accounting and charging sufficiency in a future RA proceeding. The SOD framework currently does not have a unique counting methodology and charging sufficiency requirement for energy storage resources that are long duration. LDES accounting and ensuring charging sufficiency for LDES can be addressed in multiple ways. CESA proposed an effective load carrying capability methodology to accredit LDES and ensure charging sufficiency without an explicit requirement for LSEs to show excess capacity like they do for short

[43] *See Id.,* at 8-10.

duration storage.[44] Middle River Power LLC (MRP) proposed a requirement for LSEs to show excess energy to charge pumped storage hydro like the existing requirement for short duration storage.[45] A maximum cumulative capacity bucket-like structure to ensure no one LSE over-relies on resources without sufficient other resources to charge them, an exceedance methodology to credit LDES for energy equivalent to its historic state of charge at midnight, or another methodology could also be considered. The Commission and parties should work through these different options to determine which approach is best for LDES, including pumped storage, in a future RA proceeding.

XIV. 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

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

March 3, 2025

44 *See* CESA Proposal, at 19-21.
45 *See* MRP Proposal, at 1-2.