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

Application of Pacific Gas and Electric Company (U39E) for Approval of its Demand Response Programs, Pilots and Budgets for Program Years 2023-2027	Application 22-05-002
And Related Matters.	Application 22-05-003 Application 22-05-004

**JOINT COMMUNITY CHOICE AGGREGATORS'
OPENING BRIEF ON PHASE II DR ISSUES**

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On behalf of Joint Community Choice Aggregators

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SUMMARY OF RECOMMENDATIONS

- The Commission should initiate a dual participation working group no later than 30 days following its final decision in this proceeding, allow parties to file dual participation proposals for the Commission's consideration by the end of January 2024, and issue a decision on those proposals no later than April 1, 2024;
- The Commission should establish the scope for the dual participation working group through its final decision in this proceeding, and that scope should include, at minimum, the issues and objectives described in this brief (including the development of a program participation data exchange process);
- The Commission should issue a clear directive that the IOUs must share demand response (DR) program customer participation information with community choice aggregators (CCAs) in order to facilitate dual participation prevention;
- The Commission must examine the cost effectiveness of the Emergency Load Reduction Program (ELRP) before extending that program through 2027;
- The Commission should encourage self-enrollment and cease auto-enrollment in the residential ELRP, including ceasing any re-enrollment of previously auto-enrolled customers starting in the 2024 season;
- For non-residential customers participating in ELRP sub-groups A.1 and A.2, the Commission should establish a participation floor (expressed as a percentage of nominated capacity) tied to compensation, and compensate only those customers whose participation levels surpassed that floor;
- The Commission should establish two new reporting requirements for ELRP on an annual basis:
    - Require that, at a minimum, the utilities present impacts for all ELRP Group A sub-programs at the meter-level. If device-level measurement and valuation (M&V) methods are being used in a particular sub-program for incremental load reduction (ILR) and compensation, the utilities must also report on the impact of the sub-program at the device-level;
    - Require the utilities to submit load impact protocols (LIPs) for each of the sub-programs of the ELRP on an annual basis;
- The Commission should adopt Energy Division Staff Proposal D, with the following modifications to ED's proposed definition of a "qualified" DR program:
    - Supply-side market-integrated DR programs counted for Resource Adequacy<u>, irrespective of whether the program administrator is an IOU, a CCA or a third-party demand response provider (DRP)</u>;
    - Load modifying DR programs integrated with CEC's peak demand forecasting process (such as Critical Peak Pricing rates offered by the IOUs, and potentially marginal-cost-based dynamic pricing rates should the Commission adopt such rates in the future and establish a process to integrate those rates with CEC's

forecasting process), irrespective of whether the program administrator is an IOU, a CCA or a third-party DRP;

- Any DR pilot authorized and designated by the Commission as a "qualified" DR program eligible to meet the DR enrollment requirement, irrespective of whether the program administrator is an IOU, a CCA or a third-party DRP.

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JOINT COMMUNITY CHOICE AGGREGATORS' OPENING BRIEF ON PHASE II DR ISSUES

Pursuant to the revised procedural schedule established in the January 27, 2023 *Assigned Commissioner's Ruling Directing Response to Questions and Energy Division Staff Proposals Related to Application 22-05-002 Phase II Issues and Directing Southern California Edison Company to Submit a Capacity Bidding Program Elect Proposal for Program Years 2024-2027* (January ACR), and the June 28, 2023 *Administrative Law Judge's Ruling Admitting Testimony and Exhibits into the Record and Extending Due Dates for Opening and Reply Briefs on Phase II Demand Response Issues*, the Joint Community Choice Aggregators[1] (Joint CCAs) hereby submit this Opening Brief on Phase II DR Issues.

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[1] The Joint CCAs consist of East Bay Community Energy (EBCE), Marin Clean Energy (MCE), Peninsula Clean Energy Authority (PCE), the City of San José – which operates and administers San José Clean Energy (SJCE) through the City's Community Energy Department, and Sonoma Clean Power Authority (SCP). SJCE is the City of San José's CCA program, which the San José Community Energy Department administers. Each of the CCAs in the Joint CCAs is located in Northern California, and therefore focus their testimony and participation in this proceeding on issues relevant to Pacific Gas & Electric Company's (PG&E) Application for Approval of its Demand Response Programs, Pilots, and Budgets for Program Years 2023-2027 (Application).

I. INTRODUCTION

Demand response is not a new concept, but the ways in which DR can support the State of California, the electric grid, and electric customers are rapidly evolving. PG&E's DR Application correctly observes that the effective utilization of DR resources can increasingly help mitigate the effects of wildfires, droughts, heat storms and other climate-related conditions on grid reliability.[2] The Joint CCAs agree, and submit that the effective utilization of DR resources to meet those objectives requires an "all-hands-on-deck" approach. This means the Commission should consider, in this proceeding, not only whether the investor-owned utilities' (IOUs) DR portfolios are effective and appropriate, but also how those portfolios align and intersect with the State's broader DR ecosystem—including DR programs offered by community choice aggregators (CCAs) and the California Energy Commission (CEC)—to ensure those portfolios are consistent with the fundamental DR principles the Commission articulated in Decision (D.) 16-09-056.

To that end, the Commission must revisit its "dual participation" rules—the set of principles that limit customers' ability to enroll in more than one DR program and aim to prevent double-counting of DR program impacts. Several parties, including the IOUs, agree those rules are "ripe for reconsideration"[3] because, among other things, those rules are "neither complete nor contemplate increasing complexity."[4]

To update and refresh those rules, the Commission should initiate the dual participation working group PG&E proposes.[5] Further, the Commission should require the parties develop—through the dual participation working group—a streamlined program participation data exchange process to prevent dual participation between IOU, CCA, and third-party demand response

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2 Application at 2.
3 *See e.g.* Application at 14; Exhibit PG&E-7 at 12-13:19.
4 Exhibit PG&E-8 at 1-5:29-30.
5 Exhibit PG&E-7 at 12-13 to 12-16.

provider (DRP) load-modifying DR programs. A streamlined process will help program administrators efficiently enroll customers in their respective DR programs, increase program participation and provide fair compensation while ensuring participating customers' load reductions are not double counted. In this brief, the Joint CCAs focus on describing the need for the dual participation working group, and propose a scope for that working group. The Joint CCAs also address PG&E's Emergency Load Reduction Program (ELRP) in this brief, and recommend several modifications to ensure that program meets the legal standard.

II. ARGUMENT

A. The Commission Should Initiate PG&E's Proposed Dual Participation Working Group and Direct Parties to Develop a Streamlined Data Exchange Process to Prevent Dual Participation.

The Commission established dual participation rules over ten years ago.[6] At a high level, those rules aimed to increase the amount of cost-effective DR available while ensuring that the same load reduction is neither counted nor compensated twice.[7] The rules allow customers to participate concurrently in more than one DR program provided:

1. Customers are not paid twice for the same load reduction;
2. One program is day-ahead and the other is day-of;
3. Only one of the two programs may pay a capacity payment;
4. During simultaneous events and if both programs offer energy payments, one of the energy payments is withheld.[8]

Since the Commission first adopted the dual participation rules above, both the DR program landscape, as well as the needs of California's electricity system, have evolved.[9] In recent years in particular, *load-modifying* DR programs—including all of the DR programs offered by CCAs,[10] as well as several of the sub-programs under the ELRP—have become increasingly

6 D.09-08-027 at 154-158; Ordering Paragraph (OP) 30.
7 *Id*. at 154-158; D.18-11-029 at 7.
8 D.18-11-029 at 15 (summarizing rules adopted in D.09-08-027).
9 Exhibit JCCA-01 at 4:7-8.
10 Exhibit JCCA-01 at 3:1-15; Attachments A-D (describing CCA DR programs).

prominent.[11] Those programs, and others such as the Demand Side Grid Support (DSGS) program overseen by the CEC,[12] offer customers a variety of options to benefit the grid by reshaping the net load curve, and the opportunity to provide several distinct services.[13]

The dual participation rules, however, have not kept up with the evolution of the DR market. As PG&E correctly observes, while dual participation rules serve important purposes—chiefly: avoiding double counting and double compensating the same instance of load reduction and ensuring accurate load impact measurement and attribution—existing dual participation rules "are neither complete nor contemplate increasing complexity."[14] Instead, the rules adhere to outdated dichotomies (day-ahead vs day-of, energy vs capacity) that do not reflect the diversity of current DR program offerings.[15] The Joint CCAs agree with PG&E that the rules, therefore, "are ripe for discussion" in this application proceeding.[16] Consistent with D.16-09-056, which calls for DR policies and programs to "evolve to complement the continuous changing needs of the grid," the Joint CCAs and several other parties—including California Efficiency and Demand Management Council (CEDMC),[17] the California Large Energy Consumers Association (CLECA),[18] the Public Advocates Office (PAO),[19] San Diego Gas & Electric Company (SDG&E),[20] and PG&E—therefore recommend the Commission revisit the dual participation rules.

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11 *Id*. at 4:8-11.
12 *See* Demand Side Grid Support Program, available at: https://www.energy.ca.gov/programs-and-topics/programs/demand-side-grid-support-program.
13 Exhibit JCCA-01 at 4:11-12.
14 Exhibit PGE-02 at 2-9:1.
15 Exhibit JCCA-01 at 4:13.
16 Exhibit PGE-02 at 2-9:10-11.
17 Exhibit Council-02 at 12:15-17.
18 Exhibit CLECA-01 at 31:10-11.
19 Exhibit Cal Advocates-01 at 2-2 – 2-3, lines 16-20.
20 Exhibit SDGE-10 at EBM-30:14-21.

The Joint CCAs support PG&E's proposal for a collaborative working group process to revisit the dual participation rules and request the Commission initiate that process through its final decision in this proceeding.[21] The record indicates that parties are interested in discussing a broad range of dual participation topics as a part of that working group process.[22] To promote clarity, the Commission should establish—through its final decision in this proceeding—a comprehensive scope for the dual participation working group that includes, at minimum, the following issues and objectives:[23]

1. Develop a common understanding of *existing DR programs and dual participation rules* and policies;[24]

2. Establish updated *principles and goals* for dual participation;[25]

3. Assess and establish modifications to the dual participation *rules*, considering, at a minimum, the growth of CCA and utility load-modifying programs, as well as CEC-overseen DR programs;

4. Develop and establish a bilateral customer participation *data exchange process for load-modifying DR programs* between IOUs and CCAs (and other entities as needed);

5. Develop and establish an efficient and consistent *customer unenrollment process* where dual participation is identified.

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21 Exhibit PG&E-7 at 12-14.

22 *See* Exhibit SDGE-10 at EBM-30 (suggesting working group address accurate and fair compensation for customers); Exhibit PG&E-7 at 12-15 to 12-16 (suggesting working group address level of granularity for assessing dual participation; level of visibility into CCA, CEC and third-party administered programs; program design; revision of the dual participation rules; and measurement of incrementality); Exhibit Cal Advocates-01 at 2-3 (suggesting working group address dual participation between DR, dynamic rates and energy efficiency pay-for-performance programs); Exhibit VGIC-02 at 7 (suggesting working group address value stacking).

23 The Joint CCAs do not consider this list of Scoping Objectives and Issues to be exhaustive; rather, the Joint CCAs offer this list as a minimum "starting point." The Joint CCAs acknowledge that parties may desire to discuss other issues through the dual participation working group, and the Joint CCAs do not necessarily object to additional issues. For example, the Joint CCAs generally support discussion of the "specific issues" that PG&E references in its second supplemental testimony (Exhibit PG&E-7 at 12-15 to 12-16) through the dual participation working group.

24 Exhibit PG&E-8 at 1-6. In addition, the Joint CCAs recommend that the working group establish a list of existing DR programs in California administered by the various entities (IOUs, 3rd party DRPs, CCAs, under the auspices of the CEC, etc.). A similar effort is being undertaken by the Commission in Rulemaking (R.) 18-12-006 in the Annual VGI Stocktake.

25 Exhibit PG&E-8 at 1-6.

Scoping Issues / Objectives 4 and 5 listed above are particularly critical. Scoping Issue / Objective 4 is urgent for two main reasons. First, unlike California Independent System Operator (CAISO) market integrated programs, which track customer participation via the CAISO Demand Response Registration System (DRRS), load-modifying DR programs currently lack an equivalent dual participation prevention mechanism. While at least one CCA has attempted to coordinate with PG&E to implement a load modifying DR program participation data exchange process,[26] PG&E has not cooperated to date,[27] leaving load-modifying DR programs in limbo and without any effective mechanism to track customer enrollment across program administrators. This is a major gap, because load-modifying DR programs represent a growing share of DR program offerings. All of the DR programs the CCAs currently offer are load-modifying programs, and six out of the eight sub-programs under the ELRP—which represents over 50% of PG&E's 2024-2027 DR portfolio budget[28] and has already auto-enrolled over 1.5 million residential customers—are load-modifying DR programs.[29]

Second, a *bilateral* data exchange process would not only help prevent dual participation, but would also improve each LSE's insight into the forecasted load reductions for their respective customer bases, allowing each LSE to make more accurate bidding and scheduling decisions on a daily basis.[30] Without a bilateral exchange, CCAs have limited visibility into their customers' anticipated load reductions (and when those reductions might occur), which constrains their ability to plan and dispatch their own resources effectively.[31] The Joint CCAs therefore support PG&E's

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26 Exhibit JCCA-01 at 7-8:23-3.
27 *Id*. at 8:3-4.
28 *See* Application at 20-21.
29 Exhibit JCCA-01 at 5:13-17.
30 *Id*. at 7:5-7.
31 *Id*. at 7:7-9.

recommendation that the dual participation working group address the policy, operations and privacy issues necessary to allow the exchange of program participation data on a *two-way basis*.[32]

With respect to Scoping Issue / Objective 5, as the record evidence illustrates, CCAs and third-party DRPs have experienced significant challenges when attempting to make sure that customers enrolling in their programs are unenrolled from IOU DR programs in a timely and efficient manner.[33] As OhmConnect witness Staton describes:

> The processes that currently guide customer disenrollment from IOU DR programs are burdensome and lengthy. For example, in several cases, the only way a customer can disenroll is by calling the program administrator. Some customers report difficulty getting beyond automated messages to reach a human being and give up on the process. In all instances, actual disenrollment wait times are far longer than the official times claimed by the IOUs.[34]

The Joint CCAs therefore strongly recommend the discussion of enrollment conflicts—including how to determine *which* program a dual participating customer will be unenrolled from—as a part of the dual participation working group process. The Joint CCAs further support the development of a process that promotes efficient, transparent and consistent program unenrollment as a part of the dual participation working group, as PG&E recommends in its rebuttal testimony.[35] The Joint CCAs further note that an efficient, transparent and consistent unenrollment process would meet the Commission's prior directives. In D.16-09-056, the Commission stated that DR providers "should fairly compete on a level playing field to vie for customers to enroll in their demand response programs", and, among several fundamental DR principles, articulated that "[d]emand response customers shall have the right to provide [DR]

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32 Exhibit PG&E-08 at 1-7:24-25.

33 *See* Exhibit OhmConnect-5 at 20-23 (detailing the disenrollment process for each IOU DR program and illustrating how that process can be much more burdensome and lengthy than IOUs claim).

34 *Id*. at 22.

35 Exhibit PG&E-8 at 1-18:1-3.

through a service provider of their choice" and that "demand response processes shall be transparent."[36] Similarly, in D.21-12-015, the Commission stated: "customers participating in the Residential ELRP may at any time enroll in a supply-side DR program offered by the IOU, registered third-party DRP or CCA and shall be promptly unenrolled by the IOU from ELRP without the need for any action on the part of the customer."[37]

In summary, the Joint CCAs request the Commission initiate the dual participation working group PG&E proposes, and establish a scope for that process in the final Decision of this Application proceeding that includes, at minimum, the issues and objectives described above. Importantly, the final Decision must include a specific directive for the utilities to share customer program participation information with the CCAs in order to facilitate a comprehensive dual enrollment prevention process for all DR programs (i.e. including load modifying DR programs). That directive will anchor the working group process and help ensure it is productive.

In order to ensure the timely implementation of a program participation data exchange process developed through the dual participation working group, the Joint CCAs recommend the Commission initiate the dual participation working group process no later than 30 days following its final decision in this proceeding. The Joint CCAs recommend that the Commission direct parties file dual participation proposals for the Commission's consideration by the end of January 2024, and that the Commission issue a decision on those proposals no later than April 1, 2024. This timeline would allow all entities to establish new dual enrollment prevention processes for load modifying DR programs before the 2024 summer season.

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[36] D.16-09-056 at 3, 45-46.

[37] D.21-12-015 at 58.

B. The Commission Should Modify the Emergency Load Reduction Program

The Commission authorized the ELRP as a 5-year pilot program intended to reduce peak demand during extreme weather conditions in D.21-03-056 under R.20-11-003 (the "Extreme Weather proceeding").[38] The Commission also determined in that Decision that the ELRP is subject to review and revision in the DR application proceeding.[39] In this proceeding, PG&E now proposes to continue the ELRP as a pilot through 2027.[40] As the applicant, PG&E has the burden of affirmatively establishing that its proposal to continue the ELRP is just and reasonable[41] and is in compliance with all applicable rules, regulations, resolutions and decisions.[42] Below, the Joint CCAs recommend certain modifications to the ELRP to ensure the program meets the "just and reasonable" standard and provides benefits to the State of California, the grid and electric customers.

1. The Commission must examine the ELRP's cost effectiveness before extending the program through 2027.

The ELRP pilot program has been exempt from cost-effectiveness testing to date. In D.15-11-042, the Commission found that the Demand Response Cost-Effectiveness Protocols "are not designed to measure the cost-effectiveness of **pilot programs**, technical assistance, educational,

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[38] D.21-03-056, *Decision Directing Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas and Electric Company to Take Actions to Prepare for Potential Extreme Weather in the Summers of 2021 and 2022* (Mar. 15, 2021). The Commission modified the ELRP in D.21-12-015, *Phase 2 Decision Directing Pacific Gas & Electric Company, Southern California Edison Company, and San Diego Gas and Electric Company to Take Actions to Prepare for Potential Extreme Weather in the Summers of 2022 and 2023* (Dec. 2, 2021.).

[39] D.21-03-056, Attachment 1 at 3.

[40] Exhibit PG&E-02 at 4-29:25-27.

[41] Cal. Pub. Util. Code § 451.

[42] D.12-12-030 at 42. That burden of proof is generally based upon a preponderance of the evidence. *See, e.g.* D.18-01-009 at 9-10; D.15-07-044 at 29 (observing that the Commission has the discretion to apply either the preponderance of evidence or clear and convincing standard in a ratesetting proceeding, but noting that the preponderance of evidence is the "default standard to be used unless a more stringent burden is specified by statute or the Courts.")

or marketing and outreach activities."[43] Moreover, in its decisions authorizing the ELRP, the Commission expressly waived the application of traditional cost-effectiveness tools to the ELRP through 2023.[44]

As stated above, PG&E now proposes to extend the ELRP through 2027, but asserts that evaluating the cost-effectiveness of the ELRP "is not appropriate at this time." PG&E however "believes that evaluating the pilot's cost-effectiveness is important"—presumably at some future time.[45] The Joint CCAs agree that evaluating the ELRP's cost-effectiveness is important, but submit the Commission must examine the ELRP's cost-effectiveness *before* extending the program through 2027 as PG&E proposes. The ELRP no longer meets the definition of a "pilot" program specified in the DR Cost-Effectiveness Protocols, which is a program "done for experimental or research purposes, technical assistance, educational or marketing and outreaching activities which promote DR or other energy-saving activities in general[.]"[46] Given the questionable impacts of the ELRP for various sub-groups described in Section II.B.2 below, the ELRP is not clearly providing any research purpose, technical assistance, educational or marketing and outreaching activities which promote DR or other energy-saving activities in general. While the ELRP may have been an "experimental" program in its initial phase, after three years of implementation, the program cannot reasonably be considered "experimental" anymore, and the

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43 D.15-11-042, *Decision Addressing the Valuation of Load-Modifying Demand Response and Demand Response Cost-Effectiveness Protocols*, Finding of Fact 53 at 65 (Nov. 19, 2015) (emphasis added).

44 In D.21-03-056, the Commission found that "[w]aiving the use of our traditional cost-effectiveness tools for all demand response proposals that are adopted in this decision for years 2021 and 2022 will allow for increased participation." D.21-03-056, Finding of Fact 35 (Mar. 26, 2021). Accordingly, the Commission waived the use of traditional cost-effectiveness tools for the ELRP in 2021 and 2022. D.21-03-056 at 29. In D.21-12-015, the Commission waived the use of traditional cost-effectiveness tools for the ELRP in 2023 (*Id*. at 63).

45 Exhibit PG&E-02 at 4-33:2-12.

46 2016 Demand Response Cost Effectiveness Protocols at 7 (Jul. 2016), available at: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr/demand-response-cost-effectiveness. Note however that where a load serving entity is able to quantify the costs and benefits of any particular pilot program, the Cost Effectiveness Protocols require the load serving entity to include those costs and benefits in its portfolio analysis. *Id*. at 18.

Commission should therefore revisit its classification in this proceeding.[47] Thus, the ELRP does not meet the definition of a pilot for cost-effectiveness purposes.

The best evidence that ELRP is not "experimental" is the substantial ratepayer funding PG&E requests for the program: PG&E proposes to spend $426 million on the ELRP between 2024-2027—which is over half of PG&E's total portfolio budget of $791 million.[48] The sheer magnitude of ratepayer funding for the ELRP justifies an examination of the cost-effectiveness of this program before it is extended, whether or not it remains a "pilot" in name. As the Public Advocates Office correctly states, "The Commission has an obligation to ensure that rates are just and reasonable and authorizing programs that cost ratepayers hundreds of millions of dollars per year without any indication that money is being spent efficiently is neither just nor reasonable."[49]

Several parties, including San Diego Gas & Electric Company, Tesla and the California Solar and Storage Association, argued that the ELRP should not be subject to cost-effectiveness testing because the program should be considered an "insurance policy."[50] The Joint CCAs acknowledge that the ELRP was created as an emergency pilot to address grid reliability concerns, and that the Commission specifically predicated the ELRP on its finding that the program would allow IOUs and CAISO to access load reductions during times of high grid stress and emergencies involving inadequate market resources.[51] However, this initial designation should not allow nearly half of a billion dollars of ratepayer spending to be dedicated to the ELRP program without at least an understanding of the cost-effectiveness of that spend.

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47 *See* D.21-03-056, Attachment 1 at 3 (stating that the ELRP is subject to review and revisions in this DR Application proceeding).

48 Application at 20-21.

49 Exhibit Cal Advocates-02 at 3-2:1-3.

50 *See* A.22-05-002 et al, *Tesla and CALSSA Reply Comments on January ACR* at 2 (May 5, 2023); *SDG&E Reply Comments on January ACR* at 10 (May 5, 2023).

51 D.21-03-056, Finding of Fact 17 at 64.

Notwithstanding the original factors driving the creation of the ELRP, D.21-03-056 also acknowledged that the ELRP is subject to review and revision in *this* proceeding.[52] Now that PG&E is officially proposing to roll the ELRP into its overall DR portfolio for program years 2024-2027, the Commission should no longer consider the program an "insurance policy" exempted from cost-effectiveness requirements. This approach would be consistent with the Commission's recent decision (D.23-06-055) in the energy efficiency application proceeding.[53] In that decision, the Commission found that "Market Access Programs" (MAP)—which were initially piloted for summer reliability purposes following their authorization in 2021 and were therefore exempt from cost-effectiveness requirements—are now a part of administrators' overall energy efficiency portfolios and as such, subject to cost-effectiveness requirements just like all the other programs in those portfolios.[54] The Commission should take a consistent approach here and apply cost-effectiveness requirements to the ELRP because, if PG&E's request is approved, the ELRP will be a part of PG&E's DR portfolio for program years 2024-2027.

2. *The Commission should modify the ELRP to ensure it delivers incremental load reductions .*

As stated above, the Commission created the ELRP "to allow the large electric IOUs and CAISO to access additional load reduction during times of high grid stress and emergencies involving inadequate market resources, with the goal of avoiding rotating outages while minimizing costs to ratepayers."[55] Only incremental load reduction (ILR)—defined as the load reduction achieved during an ELRP event incremental to the non-event applicable baseline and

52 D.21-03-056, Attachment 1 at 3.
53 D.23-06-055, *Decision Authorizing Energy Efficiency Portfolios for 2024-2027 and Business Plans for 2024-2031* (Jul. 3, 2023).
54 *Id*. at 76.
55 D.21-03-056 at 18, Finding of Fact 17 at 64.

any other existing commitment—is eligible for compensation under the ELRP.[56] The fundamental objective of the ELRP, therefore, is to deliver ILR.

The ELRP delivered mixed results in PG&E's service area in 2022. While the program enrolled approximately 7,000 non-residential customers (ELRP sub-groups A.1 and A.2), 3,750 customers in virtual power plant (VPP) aggregations (ELPR sub-group A.4) and 1.5 million residential customers (ELRP sub-group A.6) in 2022, customer enrollments did not consistently translate to ILR.[57] Based on the Joint CCAs' review of the *Statewide Residential Emergency Load Reduction Program Baseline Evaluation*,[58] *ELRP Data for Summer 2022 Season*,[59] and the *Draft 2022 ELRP Load Impact Protocol* (Draft ELRP LIP),[60] the Joint CCAs submit that the ELRP requires modifications in order to meet its stated goals, deliver ILR going forward, and meet the "just and reasonable" standard in Cal. Pub. Util. Code § 451.

a. The Commission should cease auto-enrollment in the residential ELRP beginning with the 2024 season.

The Draft ELRP load impact protocol (LIP) finds that residential customer auto-enrollment under ELRP sub-group A.6 did not drive meaningful ILR. It states: "The analysis of load reductions for A.6 residential enrollment status (CARE auto-enrolled, FERA auto-enrolled, HER auto-enrolled, and self-enrolled), found that the reported ex post impacts for the auto-enrolled subgroups were largely Flex Alert impacts with no or very little incremental ELRP load

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56 *Id*. at 24.

57 *See* A.22-05-002 et al, *Joint CCA Opening Comments on January ACR* at 3 (Apr. 21, 2023) (Joint CCA Opening Comments on January ACR).

58 Demand Side Analytics, Statewide Residential Emergency Load Reduction Program Baseline Evaluation (Jan. 2023).

59 *See* A.22-05-002 et al, Attachment A to Administrative Law Judge's Ruling Providing the Emergency Load Reduction Program Data for 2022 Summer Season (Mar. 2, 2023).

60 A.22-05-002 et al, Verdant Associates, Draft PG&E 2022 ELRP (Emergency Load Reduction Program) Load Impact Report (Mar. 10, 2023).

reduction."[61] In contrast, "self-enrolled ELRP participants . . . reduced their reference baseline load by an average of 10.4% during ELRP event hours and approximately 70% of the average load reduction was incremental ELRP impacts."[62] The Draft ELRP LIP therefore recommends:

- "Program managers should attempt to increase the number of self-enrolled ELRP participants to increase the ELRP incremental load reduction"; and
- "If the goal of the ELRP is to compensate customers for incremental load reduction, then ELRP should consider discontinuing auto-enrollment of customers."[63]

Indeed, as described above, the fundamental objective of the ELRP is to deliver ILR.[64] The Joint CCAs therefore strongly agree with the Draft ELRP LIP's recommendation that the Commission should encourage self-enrollment and cease auto-enrollment in the residential ELRP, including ceasing the re-enrollment of previously auto-enrolled customers, starting with the 2024 season.[65]

The Joint CCAs have previously explained other reasons why auto-enrollment in the ELRP is neither consistent with sound policy nor rational program design (beyond its failure to result in meaningful impacts).[66] Whereas D.16-09-056 established that "utilities and third-party providers should fairly compete on a level playing field to vie for customers to enroll in their demand response programs",[67] auto-enrollment tilts the DR landscape towards the IOU and undermines the CCAs' efforts to efficiently enroll customers in their DR programs.[68] For similar reasons, auto-

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[61] Joint CCA Opening Comments on January ACR at 4 (citing Draft ELRP LIP at 119). "CARE" refers to the California Alternate Rates for Energy Program, "FERA" refers to the Family Electric Rate Assistance Program, and "HER" refers to the "home energy report" program.
[62] *Id*.
[63] *Id*.
[64] D.21-03-056 at 18.
[65] *See also* Exhibit OhmConnect-4 at 9-10; San Diego Gas & Electric Company Reply Comments on January ACR at 10 (stating "auto-enrollment as a policy should not be adopted or expanded for any ELRP customer segment or rate class.")
[66] *See, e.g.* R.20-11-003, *MCE Opening Brief* at 28-32 (Sept. 10, 2021).
[67] D.16-09-056 at 52.
[68] *See* Exhibit JCCA-01 at 8 (Apr. 21, 2023) (describing the challenge of enrolling customers in CCA DR programs while avoiding dual participation violations, particularly in light of PG&E's auto-enrollment of residential customers into the Residential ELRP).

enrollment stifles innovation by DR program administrators because it may constrain customer opportunities to participate in non-IOU programs that offer higher impact and higher rewards.[69] Finally, auto-enrollment invites implementation challenges and customer confusion. Even where customers technically have the option of unenrolling from one DR program in order to enroll in another, more rewarding or impactful, DR program, the unenrollment process can be particularly burdensome and challenging where the customer *did not even know* they had been enrolled in a DR program in the first place.[70]

CCA DR programs, in contrast, do not auto-enroll customers.[71] MCE's Peak FLEXmarket program, for example, has successfully enrolled customers without relying on auto-enrollment—it enrolled 1,284 customers in 2021 and 2,264 customers in 2022.[72] The Joint CCAs note, however, that simply enrolling customers is not sufficient to deliver ILR; enrolled customers must also understand how to *effectively participate* in DR programs. Unlike technology incentive programs that reward customers for simply installing equipment (such as energy storage systems under the Self Generation Incentive Program (SGIP) or traditional energy efficiency (EE) programs), DR programs require that program participants take specific actions, or modify their baseline behavior in specific ways, during specific windows of time (for example, not running their dishwasher during peak hours).[73] In other words, they require far more *engagement* from the customer. In order for an enrolled customer to participate effectively in a DR program, program administrators must help familiarize them with the program, and help those customers understand (1) how to reduce demand; (2) when they may be asked to do so; and (3) why reducing demand can benefit

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69 *Id*.

70 *See* R.20-11-003, *OhmConnect Phase I Reply Testimony* at 5:20-21.

71 Joint CCA Opening Comments on January ACR at 6 (Apr. 21, 2023).

72 *Id.*

73 *Id*.

the grid, among other things. This process of engagement helps ensure customers take specific actions during specific windows of time, resulting in ILR.

The Joint CCAs therefore request the Commission cease auto-enrollment in the residential ELRP, including ceasing the re-enrollment of any previously enrolled customers starting in the 2024 summer season.

b. Non-residential customers should only be compensated if they deliver a minimum percentage of their nominated capacity.

The Draft ELRP LIP finds that non-residential participant nominations in sub-groups A.1 and A.2 were greatly overstated compared to actual ex-post ILR.[74] Indeed, only 21 MW out of the 400 MW of nominated capacity participated in events in 2022. The Draft ELRP LIP attributes this massive discrepancy to the fact that the ELRP does not include a mechanism that holds participants to their nominated load reductions (in other words, there is no penalty provision).[75] It recommends that the Commission use actual load impacts, and not nominated capacity, to set expectations for future years.

The Joint CCAs agree that the discrepancy between nominated capacity and actual ILR is cause for concern. Where a DR program forecasts 400 MW of nominated capacity, but only 21 MW ultimately participate in events, 380 MW of non-participating capacity are effectively "left on the table"—that capacity neither participated in the ELRP nor could it participate in other DR programs due to dual participation restrictions. In order to narrow this gap, and promote a higher ratio of participating to nominated capacity, the Joint CCAs recommend that the Commission establish a participation floor (expressed as a percentage of nominated capacity) tied to

74 *Id*. at 7 (citing Draft ELRP LIP at 119).
75 *Id*.

compensation, and compensate only those customers whose participation levels surpassed that floor.

c. The Commission should promote clarity around the measurement methods applied to the ELRP.

The Joint CCAs are concerned about the fact that the measurement and verification (M&V) methods applied to the ELRP are neither consistent within the different sub-programs of group A, nor do they align with the M&V methods applied to other DR programs in the utilities' DR portfolios. This leads to confusion among stakeholders and a general inability to compare the impact of the ELRP to other DR programs.

The first issue is that the M&V methods for the different ELRP sub-programs are neither clearly described in the ELRP's Terms & Conditions[76] for Group A, nor do they seem to be consistent between the different Group A sub-programs. More specifically, PG&E has not sufficiently explained whether it uses device-level or meter-level measurement to measure ILR for the various ELRP sub-programs.[77] It is the Joint CCAs' understanding that in the context of sub-group A.4 (VPP) and A.5 (VGI), ILR is determined (and customers are compensated) based on measurements at the device-level, but for the remaining ELRP sub-programs in group A, ILR is determined based on measurements at the meter-level. This matters, because the two measurement approaches can lead to very different results.

Assuming that device-level measurement is indeed used for sub-groups A.4 and A.5, a customer participating with a battery resource in the A.4 sub-group would be compensated for their ILR based on the kWhs that the system discharged to the home or grid, irrespective of whether

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[76] *See* Pacific Gas & Electric Company Emergency Load Reduction Program (ELRP) Pilot Group A Terms and Conditions Pursuant to California Public Utilities Commission Decision 21-03-056, 21-06-027 and 21-12-015, available at: *https://elrp.olivineinc.com/_files/pge/elrp/PGE-ELRP-Group-A-Terms-and-Conditions.pdf.*

[77] *Id*. at 8.

actual ILR were measured at the customer's meter.[78] That means, under a device-level measurement approach, the participating battery that discharges to the home or grid would be paid by the ELRP program for the load reduction, even if the load of the property on which the battery is located *increased* over the same period of time (i.e., the air conditioner was on or an electric vehicle was charging).[79] Under the same set of facts, a meter-level measurement approach would not show a load reduction, and the customer would not be paid.[80] The contrasting outcomes between meter- and device-level measurement become more complicated as customers add multiple participating devices. Consider a customer with a battery, smart thermostat, heat pump and an EV – meter-level measurements of load reductions using whole-home interval data will likely yield vastly different results as compared to the sum of device-level measurements.

The second issue that the Joint CCAs would like to highlight is the fact that the ELRP uses different M&V methods than the other DR programs under the utilities' DR portfolio. While other DR program impact evaluations are based on the load impact protocols (LIPs), PG&E explained in its report on ELRP Data for the Summer 2022 Season that the ELRP's ILR and customer compensation is based on a "the outcomes of different hypothetical baseline and settlement calculation methods" and that "None of these calculation methods are appropriate to use as a proxy for load impacts for the ELRP program."[81]

The various calculation methods used to evaluate ILR, determine compensation, and determine load impacts make it challenging for stakeholders to assess the impacts of the ELRP

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78 *Id.*
79 *Id.* at 9.
80 *Id.*
81 *See* A.22-05-002 et al, Attachment A to Administrative Law Judge's Ruling Providing the Emergency Load Reduction Program Data for 2022 Summer Season (Mar. 2, 2023).

and contrast its impact to other DR programs. To that end, the Joint CCAs recommend that the Commission establish two new reporting requirements for ELRP on an annual basis:

(1) Require that, at a minimum, the utilities present impacts for all ELRP Group A sub-programs at the meter-level. If device-level M&V methods are being used in a particular sub-program for ILR and compensation, the utilities must also report on the impact of the sub-program at the device-level;

(2) Require the utilities to submit LIPs for each of the sub-programs of the ELRP on an annual basis.

These new reporting requirements will allow parties to get a better sense of the true impacts of the ELRP and to perform an "apples-to-apples" comparison to other DR programs.

C. The Commission Should Approve the Joint CCAs' Proposed Modifications to the Definition of a "Qualified DR Program"

PG&E has proposed in its Application that the Commission develop DR enrollment requirements for customers receiving ratepayer-funded technology incentives, such as EE and Distributed Generation.[82] In R.20-05-012, the Commission acted in part on this issue, and required that customers receiving rebates for Heat Pump Water Heater appliances via the SGIP enroll in a "qualified" DR program for a minimum of three years.[83] ED Staff anticipates that the Commission may establish similar requirements in other distributed energy resources (DER) proceedings in the future. With that in mind, ED Staff proposes to define "qualified" DR programs eligible to meet a DR program enrollment requirement as a condition of a customer receiving a technology incentive or rebate as any of the following:

i. Supply-side market-integrated DR programs counted for Resource Adequacy.

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82 Exhibit PG&E-2 at 2-11, 1-14.

83 D.22-04-036 at 105-108.

ii. Load modifying DR programs integrated with CEC's peak demand forecasting process (such as Critical Peak Pricing rates offered by the IOUs, and potentially marginal-cost-based dynamic pricing rates should the Commission adopt such rates in the future and establish a process to integrate those rates with CEC's forecasting process).

iii. Any DR pilot authorized and designated by the Commission as a "qualified" DR program eligible to meet the DR enrollment requirement.

The Joint CCAs support ED's proposal. However, in the interest of promoting customer choice and flexibility, the Joint CCAs recommend the Commission clarify that the above definition applies irrespective of whether the DR program administrator is an IOU, a CCA, or a third-party DRP. To that end, the Joint CCAs propose the following modifications to ED's proposed definition of a "qualified" DR program:

i. Supply-side market-integrated DR programs counted for Resource Adequacy, irrespective of whether the program administrator is an IOU, a CCA or a third-party DRP.

ii. Load modifying DR programs integrated with CEC's peak demand forecasting process (such as Critical Peak Pricing rates offered by the IOUs, and potentially marginal-cost-based dynamic pricing rates should the Commission adopt such rates in the future and establish a process to integrate those rates with CEC's forecasting process), irrespective of whether the program administrator is an IOU, a CCA or a third-party DRP.

iii. Any DR pilot authorized and designated by the Commission as a "qualified" DR program eligible to meet the DR enrollment requirement, irrespective of whether the program administrator is an IOU, a CCA or a third-party DRP.

The Joint CCAs also support PG&E's proposal that any changes to the definition of a "Qualified Program" be made via a Tier 3 advice letter (AL). However, to the extent the Commission adopts that proposal, the Joint CCAs request the Commission clarify that CCAs are permitted to file Tier 3 ALs to propose changes to the definition of a "Qualified Program."

While the Joint CCAs support the adoption of ED Staff Proposal D with the modifications described above, the Joint CCAs continue to have implementation-related concerns with PG&E's

proposal to *require* customers receiving ratepayer-funded technology incentives enroll in a DR program. MCE expressed those concerns in its response to PG&E's Application,[84] and the Joint CCAs will not rehash those concerns in their entirety here. Briefly, to the extent the Commission adopts PG&E's proposal, program administrators will have to determine:

- How program impacts (e.g., energy savings, demand savings, and others) will be measured and assigned between programs. For instance, if a customer enrolls in a peak demand focused EE program, and is required as a result to enroll in a DR program, the incrementality rules applied to energy savings and demand reductions during peak hours will require clarification.
- How the potentially conflicting goals of technology incentive and DR programs will be reconciled. For instance, whereas a DR program may prioritize peak demand reduction, a technology incentive program, such as SGIP, may prioritize GHG reduction.

Given these substantial implementation challenges, the Joint CCAs recommend that the Commission defer a comprehensive discussion of this issue to a broader rulemaking proceeding such as the DER proceeding.[85]

III. CONCLUSION

For the reasons described in this brief and in the Joint CCAs' submissions in this proceeding, the Joint CCAs recommend the Commission:

- Initiate a dual participation working group no later than 30 days following its final decision in this proceeding, allow parties to file dual participation proposals for the Commission's consideration by the end of January 2024, and issue a decision on those proposals no later than April 1, 2024;
- Establish the scope for the dual participation working group through its final decision in this proceeding, and that scope should include, at minimum, the issues and objectives described in this brief (including the development of a program participation data exchange process);
- Issue a clear directive that the IOUs must share DR program customer participation information with CCAs in order to facilitate dual participation prevention;
- Examine the cost effectiveness of the ELRP before extending that program through 2027;

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[84] A.22-05-002 et al., *MCE Response to the Application of Pacific Gas and Electric Company for Approval of its Demand Response Programs, Pilots and Budgets for Program Years 2023-2027* at 8-10 (June 6, 2022).

[85] R.22-11-013, *Order Instituting Rulemaking to Consider Distributed Energy Resource Program Cost-Effectiveness Issues, Data Access and Use, and Equipment Performance Standards*.

- Encourage self-enrollment and cease auto-enrollment in the residential ELRP, including ceasing any re-enrollment of previously auto-enrolled customers starting in the 2024 season;
- For non-residential customers participating in ELRP sub-groups A.1 and A.2, establish a participation floor (expressed as a percentage of nominated capacity) tied to compensation, and compensate only those customers whose participation levels surpassed that floor;
- Establish two new reporting requirements for ELRP on an annual basis:
    - Require that, at a minimum, the utilities present impacts for all ELRP Group A sub-programs at the meter-level. If device-level M&V methods are being used in a particular sub-program for ILR and compensation, the utilities must also report on the impact of the sub-program at the device-level;
    - Require the utilities to submit LIPs for each of the sub-programs of the ELRP on an annual basis;
- Adopt Energy Division Staff Proposal D, with the following modifications to ED's proposed definition of a "qualified" DR program:
    - Supply-side market-integrated DR programs counted for Resource Adequacy, irrespective of whether the program administrator is an IOU, a CCA or a third-party DRP;
    - Load modifying DR programs integrated with CEC's peak demand forecasting process (such as Critical Peak Pricing rates offered by the IOUs, and potentially marginal-cost-based dynamic pricing rates should the Commission adopt such rates in the future and establish a process to integrate those rates with CEC's forecasting process), irrespective of whether the program administrator is an IOU, a CCA or a third-party DRP;
    - Any DR pilot authorized and designated by the Commission as a "qualified" DR program eligible to meet the DR enrollment requirement, irrespective of whether the program administrator is an IOU, a CCA or a third-party DRP.

Respectfully submitted,

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On behalf of Joint Community Choice Aggregators

July 14, 2023

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.21-10-002

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
APPLICATION FOR REHEARING OF DECISION 23-06-029

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July 26, 2023

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SPECIFICATION OF ERROR

California Community Choice Association hereby requests rehearing of Decision (D.) 23-06-029 (Decision) and the California Public Utilities Commission's (Commission's) prohibition of the expansion of a community choice aggregator's (CCA's) service area if the CCA had a Resource Adequacy (RA) deficient in the prior two calendar years. Rehearing should be granted based on the following legal errors set forth in the Decision:

- The Commission exceeds its jurisdiction, and therefore fails to act in the manner required by law, by acting outside of its express, narrow, and predominantly administrative authority under Public Utilities Code Section 366.2 over CCA implementation plans, and by impairing the express statutory right of customers to aggregate their loads with a CCA.

- The Commission unlawfully justifies its jurisdictional reach and impliedly exerts its authority over CCA expansion by "harmonizing" its authority under Sections 366.2 (CCA implementation), 365.1 (electric service provider (ESP) implementation), and 380 (RA rules and enforcement mechanisms), despite California law requiring express authorization of jurisdiction over CCAs as governmental bodies and not allowing harmonization of statutes when the authority set forth in such statutes is unambiguous. As such, the Commission exceeds it jurisdiction and fails to act in the manner required by law.

- The Commission misapplies and exceeds its statutory authority to prevent cost shifts by failing to identify the costs and impose them on CCA customers as required by subsections 366.2(c)(5) and 366.2(c)(7), and failing to read the more general cost shift language of Section 366.2(a)(4) in light of the requirements of Section 366.2(d), (e), and (f) regarding prevention of cost shifts in connection with CCA implementation. As such, the Commission exceeds its jurisdiction and fails to act in the manner required by law.

- The Commission overreaches in its authority to provide an "earliest possible date" for CCA expansion under Section 366.2(c)(8) by applying a requirement outside of the express statutory requirement that the Commission only consider the impact of the expansion on the investor-owned utility's (IOU's) annual procurement plan. Instead, the Commission has inserted as a factor determining the "earliest possible date" the evaluation of a CCA's RA compliance history. The Commission has thus exceeded its jurisdiction and failed to act in the manner required by law.

- The Commission violates Section 380 requiring the Commission to enforce its RA program rules in a nondiscriminatory manner by applying the rule against expansion as an additional RA enforcement policy imposed on CCAs and ESPs, but not on IOUs. The Commission violates Section 380's requirement for nondiscriminatory enforcement despite the availability of less restrictive, and nondiscriminatory, measures in Section 380 including improving the existing RA penalty structure or allocating the costs of generating capacity and demand response in a manner that prevents cost shifts. As a result, the Commission exceeds its jurisdiction and fails to act in a manner required by law.

- The Commission abuses its discretion by basing its Decision to restrict CCA expansions on conclusory, superficial, unsupported, and largely incorrect findings. As a result, the Commission has failed to act in the manner required by law.

**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.21-10-002

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
APPLICATION FOR REHEARING OF DECISION 23-06-029**

Pursuant to Rule 16.1 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure, Section 8.1 of General Order 96-B, and California Public Utilities Code Section 1731,[1] California Community Choice Association[2] (CalCCA) submits this Application for Rehearing of Decision (D.) 23-06-029[3] (Decision) issued in Rulemaking (R.) 21-10-002 on July 5, 2023. The Decision, among other things, prohibits the expansion of a community choice aggregator's (CCA's) service area if the CCA had a Resource Adequacy (RA) deficiency in the prior two calendar years. This application for rehearing is timely filed.

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

2 California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay 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 D.23-06-029, *Decision Adopting Local Capacity Obligations For 2024 - 2026, Flexible Capacity Obligations for 2024, and Program Refinements*, R.21-10-002 (July 5, 2023): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M513/K132/513132432.PDF.

I. INTRODUCTION

California Public Utilities Code Section 366.2(a) expressly entitles customers "to aggregate their electric loads as members of their local community with community choice aggregators."[4] The Commission's jurisdiction in this process is narrowly limited and primarily administrative, derived solely from the Legislature's express grants of authority over CCAs. Unlike its regulation of public utilities, the Commission has no general jurisdiction to regulate CCAs or the customers or local governments that form the CCAs.

The Decision exceeds the Commission's jurisdiction, and results in the Commission not proceeding in the manner required by law, by impairing this express right of customers to aggregate their electric loads with a CCA. Specifically, the Decision unlawfully prohibits customers from aggregating load with an existing CCA if the CCA has a history of noncompliance with the Commission's regulations governing resource adequacy (RA), promulgated under Section 380, in the prior two years (New Rule).[5]

The Commission may not, as it has done in the Decision, lawfully expand its jurisdiction to promulgate the New Rule by simply "harmonizing" statutes addressing separate subjects, particularly when there is no conflict among the statutes. And while courts may defer to the Commission's judgment in some circumstances, the Commission is not entitled to deference in its interpretation of statutes delimiting its jurisdiction.

The Commission also fails to comply with the requirement in Section 380 that it apply its RA enforcement authority in a nondiscriminatory manner to CCAs. The Commission has a range

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[4] Assembly Bill No. 117, Chapter 838 (2002) (An act to amend Sections 218.3, 366, 394, and 394.25 of, and to add Sections 331.1, 366.2, and 381.1 to, the Public Utilities Code, relating to public utilities) (AB 117).

[5] Throughout this Application for Rehearing, CalCCA refers both to the customer right to aggregate load through forming a CCA and joining an existing CCA (i.e., a CCA expansion) as CCA implementation, as both require the same Implementation Plan to be filed pursuant to Section 366.2.

of even-handed measures that can be used to address RA noncompliance without exceeding its jurisdiction over CCAs or applying enforcement mechanisms to CCAs or Electric Service Providers (ESPs) without applying the same mechanisms to investor-owned utilities (IOUs). By failing to adopt such nondiscriminatory measures, the Commission acts outside of its jurisdiction and fails to proceed in a manner required by law.

Finally, the Commission abuses its discretion and therefore fails to act in the manner required by law by making findings without explanation or support in the record. The Commission has not explained and cannot support its findings that CCA RA noncompliance is "subsidized" by other customers and affects grid reliability. Other customers do not contribute to the cost of replacement RA to account for a CCA's noncompliance, and the Commission has not asserted that such replacement purchases are made. The regulatory framework requires replacement RA resources needed to bolster reliability to be procured, instead, by the California Independent System Operator (CAISO) under Federal Energy Regulatory Commission (FERC) authority, and the costs are billed directly to the noncompliant CCA or other load-serving entity (LSE).

CalCCA requests rehearing of D.23-06-029 to correct these legal errors.

II. THE DECISION VIOLATES CUSTOMERS' STATUTORY RIGHT TO AGGREGATE THEIR ELECTRIC LOADS WITH A CCA

The Decision treads directly on the rights granted to customers by the Legislature in AB 117, set forth in Section 366.2: "[c]ustomers <u>shall</u> be entitled to aggregate their electric loads as members of their local community with [CCAs].[6] A local community's election to implement or expand a CCA program is accomplished through local ordinance.[7] AB 117 requires the Commission to

[6] § 366.2(a)(1).
[7] § 366.2(c)(12).

perform distinct, administrative, and narrowly designated tasks related to CCA implementation after a public agency's adoption of a CCA implementation plan at a duly noticed public hearing:

- Development of a cost-recovery mechanism to be imposed on a CCA pursuant to subsections [366.2] (d), (e), and (f) to be paid by the customers of the CCA to prevent shifting of costs from the CCA's implementation;[8]

- Notification to the IOU serving the customers proposed for aggregation that a CCA implementation plan has been filed (within ten days of filing);[9]

- Certification that the Commission has received the implementation plan (and any other information requested by the Commission to determine a cost-recovery mechanism) (within 90 days of filing);[10]

- Provision of findings to the CCA regarding cost recovery that must be paid by the CCA's customers to prevent cost shifting as provided for in [Section 366.2] (d), (e), and (f),[11] and authorization of implementation only if the cost recovery mechanism is imposed;[12] and

- Designation of the "earliest possible effective date" for CCA implementation, "taking into consideration the impact on" the IOU's Commission approved annual procurement plan.[13]

The Decision unlawfully expands the Commission's authority related to CCA implementation and expansion beyond that set forth in Section 366.2 by, among other things:

- Establishing the New Rule "harmoniz[ing] the statutory scheme as a whole, including Sections 380 [RA enforcement], 365.1 [direct access transactions] and 366.2";[14]

- Applying the New Rule to CCA implementation plans submitted after the effective date of the Decision,[15] beginning with the September 2023 month-ahead filing and the 2024 year-ahead RA filing due October 21, 2023;[16]

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8 § 366.2(c)(5).
9 § 366.2(c)(6).
10 § 366.2(c)(7).
11 *Ibid.*
12 § 366.2(i).
13 § 366.2(c)(8).
14 Decision, Ordering Paragraph (OP) 9 at 137.
15 *Ibid.*
16 *Id.*, OP 9 at 137.

- Applying a similar rule to ESPs but exempting the IOUs based on their current role as the Provider of Last Resort (POLR).[17]

- Excluding from the events triggering the Commission's expansion prohibition the following circumstances: (i) a year-ahead deficiency cured in the month-ahead filing, but only for year-ahead deficiencies accrued two years before the year in which the LSE files its binding load forecast;[18] (ii) a month-ahead or year-ahead system RA deficiency that is less than one percent of the LSE's system RA requirements;[19] and (iii) non-substantive "specific violations," as adopted in Resolutions E-4107 and E-4195 and modified in Decision 11-06-022.[20]

- Authorizing Energy Division to review RA referrals and citations issued by the Consumer Protection and Enforcement Division for the prior two years to determine if a CCA is eligible to expand.[21]

Neither Section 366.2 nor any other statute expressly authorize the Commission to impose the New Rule. Implicitly aware of this shortcoming, the Decision engages in hand-waving, claiming: "our approach <u>harmonizes the statutory scheme as a whole, including Sections 380, 365.1 and 366.2</u>."[22]

Rehearing of the Decision and its adoption of the New Rule should be granted to address the significant legal errors set forth therein. In the sections below, CalCCA addresses the following.

- <u>Section III</u> discusses relevant legal authority on the scope of Commission jurisdiction and each of the purportedly "harmonized" statutes, noting, *inter alia*, that the authority permitting the Commission to regulate the acts of a public body

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[17] *Ibid.*

[18] *Id.* at 40, OP 10 at 138. Year-ahead deficiencies in the year that the LSE files its binding load forecast with additional load it intends to serve are not eligible for exclusion from the expansion prohibition. *Ibid*. The Commission states that there will be insufficient time for the LSE to cure the year-ahead deficiency in that year's month-ahead timeframe as the LSE will have already filed its binding load forecast commitments. *Ibid.*

[19] Note that OP 10 describes a "month-ahead or <u>system</u>-ahead system RA deficiency," however CalCCA believes the Commission means "<u>year</u>-ahead system RA deficiency." *See id.* Clarification on OP 10 is therefore necessary. *Ibid.*

[20] *Ibid.*; *see* D.11-06-022, *Decision Adopting Local Procurement Obligations for 2012 and Further Refining the Resource Adequacy Program*, R.09-10-032 (June 23, 2011): https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/138375.PDF.

[21] *Id.*, OP 11 at 138-139.

[22] *Id.* at 115 (emphasis added).

must be "express," and not simply inferred.[23] Section III also discusses California law refuting the ability to "harmonize" distinct statutes to obtain a result other than what is expressly provided in a statute. Section III also emphasizes that the usual deference provided by courts to the Commission's interpretation of its governing statutes does not extend to the Commission's interpretation of its own jurisdiction.

- Section IV examines the law set forth in Section III in the context of the Decision, describing the legal errors committed by the Commission.
- Section V. describes the failure of the Commission to act within its jurisdiction granted through Section 380 to apply the RA enforcement mechanism in a nondiscriminatory manner.
- Section VI describes the Commission's abuse of discretion resulting from the lack of evidence or analysis supporting its conclusions in the Decision.

III. RELEVANT LEGAL AUTHORITY ON COMMISSION JURISDICTION

A. The Commission's Jurisdiction Derives from Authority Expressly Granted by the Legislature

Except as expressly authorized or directed by the Legislature, the Commission has no jurisdiction over the actions of local government bodies such as CCAs, which form either as a municipality or a joint powers authority. In this regard, its jurisdiction differs greatly from its general authority over IOUs. The following describes the parameters of Commission jurisdiction over IOUs versus other entities.

The Commission's overall authority stems from the California Constitution,[24] which grants the Commission broad authority to regulate transportation companies[25] and vests the Legislature with control over privately owned providers of energy, water and telecommunications.[26] The Constitution provides that "the Legislature has plenary power . . . to

23 *Santa Clara Valley Transp. Auth. v. Pub. Utils. Comm'n* (2004) 124 Cal.App.4th 346, 364.
24 *San Diego Gas & Elec. Co. v. Super. Ct.* (1996) 13 Cal.4th 893, 914; Cal. Const., Art. XII, §§ 1-6.
25 Cal. Const., Art. XII, § 4.
26 *Id.*, Art. XII, § 3.

confer additional authority and jurisdiction upon the [C]ommission."[27] The Legislature exercised this plenary power by enacting the Public Utilities Code, vesting the Commission with broad authority to "supervise and regulate every public utility in the State"[28] and to "do all things, whether specifically designated in [the Public Utilities Code] or in addition thereto, which are necessary and convenient in the exercise of such power and jurisdiction."[29] While the Commission's authority over public utilities (i.e., IOUs) is broad, courts have even placed limits on this authority, including finding that the Commission is not authorized to disregard express legislative directives or restrictions upon its powers found in other statutes.[30]

1. The Commission Has No Jurisdiction Over the Actions of Local Government Bodies Such as CCAs Except as Expressly Authorized by the Legislature

Established law provides that except as authorized or directed by the Legislature, the Commission has no jurisdiction over the actions of government bodies such as CCAs.[31] Any authority granted by the Legislature, however, must be "express" and not simply inferred. In other words, the Commission should not presume the Legislature intended "to legislate by

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27 *Id.,* Art. XII, § 5.

28 *San Diego Gas & Electric,* 13 Cal.4th at 915; *see also* Section 701.

29 Section 701; *see also* Section 451 (Commission authority to ensure public utilities operate safely); *see also* Section 702 (public utilities must obey and comply with all Commission orders as to any matter affecting its business as a public utility).

30 *See Assemb. v. Pub. Utils. Comm'n* (1995) 12 Cal.4th 87, 103 (finding that an express legislative directive in Public Utilities Code Section 453.5 that a ratepayer refund be paid to the ratepayers of public utilities prevented the Commission from diverting that refund for other public purposes); *see also Pac. Tel. & Tel. Co. v. Pub. Util. Comm'n* (1965) 62 Cal.2d 634, 653 (Section 701 inapplicable because the actions of the Commission disregarded "express legislative directives").

31 *See Monterey Peninsula Water Mgmt. Dist. v. California Pub. Utils. Comm'n* (2016) 62 Cal.4th 693, 698 (2016) ("Public Utilities Commission … has no authority, however, to regulate public agencies like the District, absent a statute expressly authorizing such regulation…"); *see also County of Inyo v. Pub. Utils. Comm'n* (1980) 26 Cal.3d 154, 166-167 (citing *Los Angeles Metro. Transit Auth. v. Pub. Utils. Comm'n* (1959) 52 Cal.2d 655, 661 ("In the absence of legislation otherwise providing, the commission's jurisdiction to regulate public utilities extends only to the regulation of privately owned utilities").

implication"[32] – the modern rule of construction disfavors such practice.[33] In fact, even where the activity of a government body has some relationship to an activity of a Commission-regulated utility, the Commission lacks jurisdiction over the government body's activity in the absence of express legislative authority for the Commission action at issue.[34] For this reason, the California Supreme Court held in *Monterey* that the Commission lacked jurisdiction to review a user fee imposed by a government body even though the user fee itself was billed and collected, on behalf of the government body, by a Commission-regulated utility.[35] Therefore, without express Legislative authority, the Commission lacks jurisdiction to delay customers' exercise of their rights "to aggregate their electric loads as members of their local community with community choice aggregators" under Section 366.2(a)(1).

2. The Commission Justifies Its Decision by "Harmonizing" Its Statutory Authority in Sections 366.2, 365.1, and 380

While the Commission lacks express authority to justify its New Rule, it reasons that the Decision is justified because it "harmonizes the statutory scheme as a whole, including Sections 380, 365.1 and 366.2."[36] These sections, however, serve unique, separate, and nonconflicting purposes and do not separately or together provide the jurisdiction that the Commission claims: (i) Section 380 authorizes the Commission to oversee a CCA's RA activities; (ii) Section 365.1 governs direct access – not CCA – transactions and authorizes the Commission to recover costs from bundled and unbundled (including direct access and CCA) customers for Commission

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32 *People v. Welch* (1971) 20 Cal.App.3d 997, 1002 (citing *First M.E. Church v. Los Angeles Co.* (1928) 204 Cal. 201, 204.

33 *See Educ. & Recreational Servs., Inc. v. Pasadena Unified Sch. Dist.* (1977) 65 Cal.App.3d 775, 782 (rejecting an argument that the Legislature implied meaning in a statute); *see also San Diego Serv. Auth. for Freeway Emergencies v. Super. Ct.* (1988) 198 Cal.App.3d 1466, 1472 ("a Court should not presume the Legislature intended to legislate by implication") (citing *People v. Welch* (1971) 20 Cal.App.3d at 1002).

34 *See Monterey,* 62 Cal.4th at 699-700.

35 *Ibid*.

36 Decision at 115.

authorized or ordered central procurement of RA by an IOU; and (iii) Section 366.2 governs implementation of a new or expanded CCA. Each separate and distinct area of statutory authority is described below.

a. Section 366.2 Establishes a Detailed, Narrow Scope of Commission Jurisdiction Over CCA Implementation and Expansion

As discussed in Section II above, the Commission's authority in connection with CCA implementation is expressly set forth in Section 366.2. The statute prescribes the rights and obligations of customers aggregating their load through a CCA, the responsibilities of the CCA, and the Commission's, narrow, distinct, and largely administrative roles in the implementation process to:

- "[N]otify any electrical corporation serving the customers for aggregation that an implementation plan initiating [CCA] has been filed" (within 10 days of implementation plan filing);[37]
- Seek "information …. that the commission determines is necessary to develop the cost-recovery mechanism in subdivisions (d), (e), and (f)";[38]
- "Certify" that it "has received the implementation plan, including any additional information necessary to determine a cost-recovery mechanism" (within 90 days of implementation plan filing);[39]
- Provide the CCA with findings regarding any cost recovery to be paid by customers of the CCA to prevent cost shifting as provided for in Sections 366.2 (d), (e), and (f)[40] and authorize implementation only if the cost recovery mechanism is imposed;[41]
- "[D]esignate the earliest possible effective date for implementation" of the CCA program "taking into consideration the impact on any annual procurement plan of the electrical corporation that has been approved by the commission";[42] and

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37 § 366.2(c)(6).
38 § 366.2(c)(5).
39 § 366.2(c)(7).
40 *Ibid.*
41 § 366.2(i).
42 § 366.2(c)(8).

- Oversee electrical corporation cooperation in the implementation of the CCA program.[43]

The New Rule, effectively extending the Commission's jurisdiction over CCA implementation, is not expressly provided for in Section 366.2, or in any other statute.

The Decision's expansion of jurisdiction conflicts with the Commission's prior express and clear acknowledgement of the limits of its jurisdiction over CCAs. In its first major decision on implementation, the Commission concluded that AB 117 does not confer authority for "general regulatory oversight of CCAs"[44] and further clarified its belief that nothing in "AB 117 intended to give this Commission broad jurisdiction over CCAs."[45] In focusing specifically on the regulatory process for considering CCA implementation, it found that: "AB 117 does not provide us with authority to approve or reject a CCA's implementation plan or to decertify a CCA."[46] Importantly, it also concluded that its jurisdiction was limited by the express terms of the statute: "We assume that if the Legislature intended for us to regulate the CCA's implementation plan in other ways, the Legislature would have included explicit language in the statute with regard to its intent."[47]

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43 § 366.2(c)(9).

44 D.05-12-041, *Decision Resolving Phase 2 Issues on Implementation of Community Choice Aggregation Program and Related Matters,* R.03-10-003 (Dec. 15, 2005), Conclusion of Law (COL) 2, at 60; *see also id.* COL 1, at 60 and Finding of Fact (FOF) 2, at 56: https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/52127.PDF.

45 *Id.* at 16; *see also* D.12-09-021, *Order Denying Rehearing of Resolution E-4250*, Application 10-05-015 (Sept. 13, 2012) (the Commission acknowledges its "limited jurisdiction over CCAs" in contrast to its "general jurisdiction" over IOUs).

46 D.05-12-041, at 4; *see also id.,* at 14 ("we find nothing in the statute that directs the Commission to approve or disapprove an implementation plan or modifications to it. Nor does the statute provide explicit authority to 'decertify' a CCA or its implementation plan").

47 *Id.* at 15. The Commission seems to suggest that D.05-12-041 claimed authority to terminate a CCA's service. *See* Decision at 37. The quoted language omits key elements of the relevant finding of fact in D.05-12-041 and the underlying discussion. The Commission contemplated termination "in the event of a system emergency or where public health or safety is involved" and then only after an order by the Commission. *See* D.05-12-041 at 49. Moreover, the Commission has never terminated a CCA service for any reason and thus the scope of its authority has not been tested by a court.

As discussed further in Section IV.C, the New Rule, by interpreting the Commission's "overall" and "harmonized" authority in Sections 365.1, 366.2 and 380, ignores this previous acknowledgment of the Commission's narrowly established authority over CCA implementation.

b. Section 380 Establishes the Scope of Commission Jurisdiction Over CCAs' Resource Adequacy Activities

As discussed above, the Decision claims to have "harmonized" Section 366.2 with Section 380 to justify the New Rule for CCAs.[48] Section 380, granting authority to the Commission to establish RA requirements for all LSEs (including CCAs), neither addresses nor provides any authority to the Commission over CCA implementation plans. Instead, this statute represents an entirely separate authority addressing oversight of RA once a CCA is operational.

The Commission has developed its RA program over nearly two decades; its first key decision framed the program in 2004[49] with requirements very similar to those of the current program. Not until the adoption of AB 380 (Nunez, 2005), however, did the Legislature expressly grant the Commission authority to oversee the RA activities of CCAs. Section 380 provides the Commission authority to establish an RA program to ensure the reliability of electric service in California, which applies equally to all LSEs, including IOUs, CCAs, and ESPs.[50] Although Section 366.2 was enacted in 2002, AB 380 (enacted in 2005) did not alter or cross-reference Section 366.2.

Section 380 does not provide authority for the Commission to tie a CCA's RA compliance history to its implementation. However, Section 380 expressly contains four

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48 Decision at 115.

49 D.04-01-050, *Interim Opinion*, Order Instituting Rulemaking to Establish Policies and Cost Recovery Mechanisms for Generation Procurement and Renewable Resource Development, R.01-10-024 (Jan. 22, 2004), at 10-17: https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/33625.PDF.

50 § 380 applies to "load serving entities" as defined in subdivision (k).

important directives relevant to the reliability issues that the Commission purports to address in the Decision. First, it expressly gives the Commission a tool to prevent cost shifting among customers, requiring the Commission to "[e]quitably allocate the cost of generating capacity and demand response in a manner that prevents the shifting of costs between customer classes."[51] Second, it authorizes the Commission to ensure compliance with its RA program through the exercise of its enforcement powers.[52] Third, it must exercise its powers in a way that "[m]inimize[s] enforcement requirements and costs" and in a "nondiscriminatory manner."[53] Fourth, it requires the Commission to determine "the most efficient and equitable means" for achieving the goals set forth in Section 380.[54] Importantly, nothing in Section 380 expressly establishes a new enforcement power related to CCA implementation plans or permits the Commission to tie its RA enforcement authority to any distinct authority the Commission holds in another statute such as Section 366.2.

c. Section 365.1 Among Other Things, Governs Direct Access and Cost Recovery for Centralized Resource Adequacy Procurement

The Decision relies not only on Sections 366.2 and 380 but contends that these provisions have also been harmonized with a third Section, 365.1, to justify the Commission's action.[55] While the Commission summarily states that it "disagrees that …Section 365.1 constrain[s] the Commission's ability to ensure CCAs seeking to expand service of meeting their RA requirements,"[56] the Decision does not explain where in the 1,300 words of Section 365.1 it finds support for its position. CalCCA agrees that this section does not expressly "constrain" the

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51 § 380(b)(3) (original Section 380(b)(2)).
52 § 380(e).
53 *Id*.
54 § 380(h).
55 Decision at 115.
56 *Ibid*.

Commission's action but neither does it expressly authorize or justify its New Rule. On its face, the section seems irrelevant to the question at hand given that it predominantly governs direct access.

In fact, only subdivisions (c) and (d) of Section 365.1 apply to CCAs; the other sections apply to "other providers" (such as ESPs) which expressly excludes CCAs.[57] The two applicable subdivisions prescribe the cost recovery mechanism to address circumstances in which the Commission orders an IOU pursuant to Section 380 to centrally procure RA generation resources for the benefit of all customers. Neither subdivision expressly authorizes the Commission to do so by rejecting an expansion plan of a CCA. It is unclear how the Commission "harmonized" this statute with other statutes to support its New Rule.

B. The Commission's Construction of Statutes Delimiting Its Jurisdiction is Not Entitled to Deference by Courts

Because the Commission may only take actions with respect to government bodies that are expressly authorized by the Legislature, whether the Commission has exceeded its jurisdiction will often turn on the construction of a statute purportedly providing that express authority. Unlike the deference granted by courts to the Commission's interpretation of statutes subject to the regulatory jurisdiction of the Commission, its construction of the scope of its authority under such statutes is entitled to no deference by a reviewing court.[58] Instead, construction of the statute at issue is subject to independent review.[59]

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57 § 365.1(a).

58 *See Santa Clara Valley,* 124 Cal.App.4th at 359 ("This case turns on statutory interpretation and issues of legislative intent underlying sections 1201 and 1202 as well as the VTA's enabling legislation and related statutes applicable to public light rail transit systems. … Therefore, our review is independent review"); *see also PG&E Corp. v. Pub. Utils. Comm'n* (2004) 118 Cal.App.4th 1174, 1194-95 ("the general rule of deference to interpretations of statutes subject to the regulatory jurisdiction of agencies does not apply when the issue is the scope of the agency's jurisdiction…(Citations omitted)…..We conclude that the PUC's interpretation of the scope of its own jurisdiction must bear more than just a "reasonable relation" to statutory purposes and language…").

59 *See Santa Clara Valley,* 124 Cal.App.4th at 359; *see also PG&E Corp.,* 118 Cal.App.4th at 1194-95.

Here, the Commission contends that its jurisdiction to delay or prevent CCA expansion turns on the harmonization of three statutes: Sections 366.2, Section 380, and Section 365.1.[60] As discussed above, none of these statutes independently provides the requisite authority to reject or delay the rights of local communities to adopt community choice, whether through a new or expanded CCA. Section 366.2 establishes in great detail the narrow scope of the Commission's role in reviewing a CCA's implementation plan. Section 380 separately prescribes the scope of the Commission's jurisdiction over CCAs in regulating their RA activities. Section 365.1 primarily applies to direct access and ESPs; subdivisions (c) and (d), however, address cost recovery for all customers for any centralized resource adequacy procurement the Commission directs. None of these statutes expressly authorizes the Commission to delay or prevent expansion of CCA service. In the event of court review of the Decision, the Commission's novel "harmonization" of the three statutes to grab authority not otherwise expressly provided by statute will be subject to a Court's independent review.

IV. THE DECISION EXCEEDS THE COMMISSION'S JURISDICTION BY PROHIBITING CUSTOMERS FROM AGGREGATING THEIR LOADS WITH AN EXISTING CCA BASED ON THE CCA'S PRIOR RA COMPLIANCE HISTORY

A. The Legislature Has Not Expressly Authorized the Commission's Action

The Commission has exceeded its limited jurisdiction over CCAs by conditioning a local community's aggregation of customer loads with an existing CCA on the existing CCA's RA compliance history. As explained in Section III.A.1, the Commission has no general authority over local governments absent express statutory authority. Moreover, nothing in the three statutes cited by the Decision – Sections 366.2, 365.1, or 380 expressly authorizes the Commission to take this action; indeed, the Decision claims no express authority. In adopting the New Rule to prohibit

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60 Decision at 115.

customers from aggregating their loads with an existing CCA based on the CCA's prior RA compliance history, the Decision therefore exceeds the Commission's jurisdiction.

The Commission must look to the plain language of Section 366.2, which clearly and in great detail delineates the role of the Commission in CCA implementation. Nothing in that language permits the Commission to prevent or delay implementation of an expansion based on the existing CCA's RA compliance history.

B. The Decision Exceeds the Commission's Statutory Jurisdiction to Prevent Cost Shifts

The Decision appears to suggest that its New Rule has been adopted to prevent cost shifting among customer classes. Finding of Fact 6 states: "LSEs that are deficient in their RA obligations result in reliance on other LSEs' procurement activities and cost-shifting."[61] It further observes its duty to prevent cost shifting in Section 366.2(a)(4) and to allocate costs equitably under Section 380.[62] While the Legislature has delegated these responsibilities to the Commission, the Commission misapplies and exceeds its authority.

As an initial matter, the misapplication of its authority is unmistakable in its choice of remedies to address the purported cost shift. Preventing cost shifts for CCA implementation, as Section 366.2(c)(5) describes, is achieved by identifying the costs that "shall be paid by the customers of the community choice aggregator." The Commission has historically identified such costs in its Power Charge Indifference Adjustment (PCIA) proceeding, R.17-06-026,[63] and the proceeding's predecessors. The Commission calculates these costs annually in each IOU's

61 Decision at 130.
62 *Id.* at 36.
63 *See generally, e.g.,* D.18-10-019, *Decision Modifying the Power Charge Indifference Adjustment Methodology*, R.17-06-026 (Oct. 11, 2018): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M232/K687/232687030.PDF.

Energy Resource Recovery Account (ERRA) proceeding,[64] and imposes the costs as a nonbypassable charge on each customer's bill. If the Commission believes, as it suggests in the Decision, that a cost shift was occurring, its statutory authority requires it to identify the cost and impose it on CCA customers, not to prevent or delay a CCA's expansion.

Likewise, the Commission has equitably allocated reliability costs under Section 380 for many years, using its Cost Allocation Mechanism, both on a collective[65] and individual LSE[66] basis. Nothing in the Decision, however, suggests that there is a need for reallocation of any reliability costs. In short, if the problem was purported cost shifting, the Commission failed to deploy the remedy the Legislature provided: allocation of centrally procured RA costs.

In addition, the types of costs the Commission has identified as a potential "cost shift" fall outside the bounds of its authority under Section 366.2(c)(7). This section defines the scope of cost shifts the Commission is authorized to address in CCA implementation, pointing to subdivisions (d), (e), and (f). These costs currently are addressed in the Commission's PCIA proceeding, R.17-06-026. The Decision goes beyond these categories and institutes new and statutorily undelineated cost shift policy based upon RA deficiencies.

Specifically, Section 366.2 permits recovery of several categories of costs as defined in subdivisions (d), (e), and (f). Subdivisions (d) and (e) require recovery from CCA customers of

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64 *See, e.g.,* D.22-12-044, *Decision Adopting the Electric Revenue Requirements and Rates Associated with the 2023 Energy Resource Recovery Account and Generation Non-bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation and the 2023 Electric Sales Forecast for Pacific Gas and Electric Company*, A.22-05-029 (Dec. 15, 2022): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M500/K043/500043722.PDF.

65 D.06-07-029, *Opinion on New Generation and Long-Term Contract Proposals and Cost Allocation*, R.06-02-013 (July 20, 2006): https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/58268.PDF.

66 D.22-05-015, *Decision on Modified Cost Allocation Mechanism for Opt-Out and Backstop Procurement Obligations*, R.20-05-003 (May 23, 2022): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M479/K339/479339449.PDF.

Department of Water Resources (DWR) costs stemming from the 2000-2001 energy crisis. Subdivision (f) requires recovery of the IOU's "past undercollections" for IOU purchases prior to the load departing. The statute provides no other express categories of cost recovery in the CCA implementation process.

The types of cost shift addressed by the Decision go beyond the scope of this express authority. The Decision finds "that LSEs that are deficient in their RA obligations result in leaning on other LSEs' procurement activities."[67] The Decision asserts that "if one LSE fails to contract for resources to serve its own load, the customers of other LSEs that did accomplish such forward contracting are effectively subsidizing the deficient LSE's energy procurement, and such deficiencies may impact grid reliability."[68] These costs do not fall within the scope of subdivisions (d), (e), or (f) and, critically, the Decision does not claim otherwise.

Finally, the more general language of Section 366.2(a)(4) must be read within the context of the overall implementation statute. Subdivision (a)(4) provides that "[t]he implementation of a community choice aggregation program shall not result in a shifting of costs between the customers of the community choice aggregator and the bundled service customers of an electrical corporation." While subsection (a)(4) provides the principle, it is informed by later subdivisions (d), (e), and (f) to provide the explicit mechanisms to prevent such cost shifting.

Fundamental rules of statutory construction require reading together the sections within a statutory provision.[69] Harmonizing the subsections of Section 366.2, the legislative intent is clear: subsections (d), (e), and (f) are the methodologies provided by the Legislature to prevent the cost

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67 Decision at 37-38.

68 *Id.* at 37.

69 *See Select Base Materials v. Bd. of Equalization* (1959) 51 Cal.2d 640, 645; *see also Moyer v. Workmen's Comp. Appeals Bd.* (1973) 10 Cal.3d 222, 230-31 (citing *Select Base Materials,* 51 Cal.2d at 645).

shifting identified in subsection (a)(4) that may result from the implementation of the CCA program. In other words, subsection (a)(4) was not enacted in a vacuum and does not alone provide the Commission authority to prevent cost shifting outside of Section 366.2's parameters.

C. The Commission May Not Rewrite Existing Law to Imply Jurisdiction to Establish the New Rule by "Harmonizing" the Statutory Scheme as a Whole

The Commission cannot cure its lack of jurisdiction through the Decision's misapplication of a canon of statutory interpretation. Lacking express statutory authority for its action, the Decision touts its "new requirement" as falling "under the umbrella of reliability and [RA] for CCAs planning to implement an expansion."[70] The Commission rests its action on its "statutory obligations to ensure energy reliability at just and reasonable rates and specific authority to ensure RA compliance" and its theory that "harmonizes the statutory scheme as a whole, including Sections 380, 365.1 and 366.2."[71] As an initial matter, the Decision lacks any explanation of the ambiguity or conflict the harmonization was intended to address or the rationale supporting its conclusion. Even if there were a cogent explanation, however, the Commission cannot simply rewrite existing law by tying together two limited grants of authority on separate subject matters – certification of CCA implementation and RA enforcement authority over all LSEs – to create an overarching "new" requirement for CCAs.

Harmonization, as a canon of statutory construction, is the process of reconciling conflicting statutes and interpreting them in a way that gives effect to the intent of the legislature. Statutory construction begins with the plain language of the statutes and "their respective texts."[72] In general, "[i]f two seemingly inconsistent statutes conflict, the court's role is to

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70 Decision at 37.

71 *Id.* at 115.

72 *State Dept. of Pub. Health v. Super. Ct.* (2015) 60 Cal.4th 940, 956 (citing *Pineda v. Williams–Sonoma Stores, Inc*. (2011) 51 Cal.4th 524, 529 ("we look first to the words of a statute, 'because they generally provide the most reliable indicator of legislative intent'")).

harmonize the law."[73] As the California Supreme Court observed: "The cases in which we have harmonized potentially conflicting statutes involve choosing one plausible construction of a statute over another in order to avoid a conflict with a second statute."[74] Moreover those statutes must relate to the same subject.[75] Courts have made clear, however, that "the requirement that courts harmonize potentially inconsistent statutes when possible is not a license to redraft the statutes to strike a compromise that the Legislature did not reach."[76]

The California First District Court of Appeals addresses strikingly similar circumstances in 2022 in *Shiheiber v. JPMorgan Chase Bank, N.A.*[77] In *Shiheiber*, the cross-complainant Henderson attempted to interpret Civil Procedure Code Section 575.2, providing enforcement mechanisms for superior courts for their local rules, by reading it in the "context of its surrounding statutes" including Sections 575 and 128.5.[78] The court first finds that "[g]iven its entirely different language, subject and provenance, section 575 [governing rules adopted by the Judicial Council] simply has no bearing on the interpretation of section 575.2."[79] The Court concludes:

> [C]ontrary to Henderson's suggestion that there is something in section 575 with which section 575.2 must be "harmonized," she points to no conflict between the two sections, and we can conceive of none.[80]

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73 *Stone St. Capital, LLC v. California State Lottery Comm'n* (2008) 165 Cal.App.4th 109, 118-119 (citations omitted).

74 *State Dept. of Pub. Health,* 60 Cal.4th at 956 (citations omitted); *see also Grassi v. Super. Court* (2021) 73 Cal.App.5th 283, 307(citations omitted).

75 *See Wirth v. St. of California* (2006) 142 Cal.App.4th 131, 140 (citations omitted) (finding statutes addressing "salary and benefits" and "supervisory compensation differential" on the same matter); *see also Med. Bd. of California v. Super. Ct.* (2001) 88 Cal.App.4th 1001, 1015 (finding statutes addressing discipline action for a licensee on the same matter).

76 *St. Dept. of Pub. Health,* 60 Cal.4th at 956 (citations omitted); *see also Grassi*, 73 Cal.App.5th at 307 (citations omitted).

77 *Shiheiber v. JP Morgan Chase Bank, N.A*. (2022) 81 Cal.App.5th 688.

78 *Id.* at 699.

79 *Ibid.*

80 *Ibid*.

Henderson also argued that Section 575.2 must only be applied under the broader rules set forth in Section 128.5, requiring a showing of bad faith for sanctions. The Court observes that "Henderson makes *no* attempt at any valid exercise in statutory interpretation" of the unambiguous meaning of Section 575.2 (which does not require the bad faith showing).[81] The Court finds that:

> . . . Henderson does not engage at all with the statutory text. She has identified no ambiguity in the statutory language that calls for judicial construction, much less has she articulated any cogent reason for us to read into the statutory language a limitation the Legislature did not state expressly.[82]

Shiheiber is highly instructive in this case given that the court refuses in two instances to "harmonize" statutes when the unambiguous meaning of such statutes is clear. In the Decision, the Commission attempts harmonization similar to Henderson, when the meaning of Sections 365.1, 366.2, and 380 are unambiguous. As in *Shiheiber,* however, no legal reason exists to "harmonize" the statutes except for the Commission attempting to justify its expansion of jurisdiction.

The Commission has done just what California courts forbid: it either has rewritten Section 366.2 to include a new criterion for certification of a CCA implementation plan or rewritten Section 380 to override the very specific CCA implementation directives in Section 366.2. In the case of the Commission's New Rule, there is no conflict or inconsistency among the statutes the Decision relies on and thus no reason to "harmonize" those statutes; the Commission cites no such conflict. Instead, the statutes simply address different subjects of regulation. Section 366.2 governs implementation or "start-up" of a CCA, while Sections 380 and 365.1 govern RA activities of an operational CCA or direct access provider.

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81 *Id.* at 701 (emphasis in original).

82 *Id.* at 702.

There is no conflict among these provisions. Even if there *were* a conflict between Sections 366.2 and 380, it would be one of the Commission's own creation. Nothing in the language of Section 366.2 prevents the Commission from administering and enforcing the RA program governing CCAs. Indeed, the Commission has overseen and enforced the RA program under Section 380 without the New Rule, as discussed in greater detail in Section V. Similarly, nothing in the language of Section 380 prevents the Commission from administering Section 366.2 as the Legislature directed. Only when deploying the New Rule as an RA enforcement mechanism does it become a conflict. Had the Commission remained in the lanes the Legislature created, continuing to revise and improve its RA penalty structure, there would be no problem.

D. The Commission's Excursion Outside the Scope of Its Jurisdiction Cannot Be Justified by Its Obligation to Provide a CCA the "Earliest Possible Date" for Implementation

The Decision, in its effort to find a solid legal basis for its action, cites the Commission's statutory authority to set the effective date for a CCA planned implementation as an invitation for the Commission to review and base the effective date on a CCA's history of RA deficiencies.[83] The Commission reasons that the RA compliance history demonstrates a CCA's inability to serve its existing customers and therefore is relevant to the planned expansion date.[84] The Commission purportedly justifies this overreach of its authority under 366.2(c)(8)'s requirement that the Commission "designate the earliest possible date for implementation of a community choice aggregation program taking into consideration the impact on any annual procurement plan of the electrical corporation that has been approved by the commission." Again, this reasoning is misplaced, and the requirement cannot justify the Commission's New Rule.

[83] Decision at 38.
[84] *Id.*

First, the context of the statute makes clear that the "earliest possible date" is something specified *after* an implementation plan is filed. Indeed, this subdivision follows the subdivisions delineating rules for submission of implementation plans ((c)(4)), identification of cost recovery to prevent cost shifts ((c)(5)), notice of implementation plans to the IOU ((c)(6)), and certification of a plan ((c)(7)). In setting the "earliest possible date," the statute expressly provides the only factor the Commission is permitted to consider – "the impact on any annual procurement plan of the electrical corporation that has been approved by the commission."[85] The Commission's New Rule, inserting the evaluation of a CCA's RA compliance history as an additional factor, does not comport with this limitation. The reference to the IOU's approved procurement plan is informed by Section 454.5, which describes in great detail the requirement that an IOU file and submit a procurement plan for Commission approval. The procurement plan is intended to detail the IOUs' "procurement of electricity for its retail customers."[86] Indeed, this requirement is fulfilled by the IOUs' BPPs which are updated periodically.[87] Section 366.2(c)(8) therefore contains a specific requirement intended to ensure that the CCA's implementation will be accounted for vis a vis the relevant IOU's procurement plan.

The New Rule, however, instead will result in the setting of the "earliest possible date" without reference to any approved IOU BPP, but rather to a CCA's RA compliance history. The Decision attempts to rebut the argument that the Commission is limited to considering the bundled procurement plan as set forth in Section 366.2(c)(8) with backbends:

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85 § 366.2(c)(8).

86 § 454.5(a). For example, the 2021 Bundled Procurement Plan (BPP) for PG&E approved by the Commission states: " PG&E's BPP describes in detail its planning, procurement, and scheduling and bidding processes, all of which are designed to enable PG&E to provide reliable, cost-effective bundled electric service." PG&E's Bundled Procurement Plan - Public Version (pge.com)

87 *See, e.g.,* D.12-01-033, *Decision Approving Modified Bundled Procurement Plans*, R.10-05-006 (Jan. 12, 2012): https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/157640.PDF.

> These arguments ignore that if one LSE fails to contract for resources to serve its own load, the customers of other LSEs that did accomplish such forward contracting are effectively subsidizing the deficient LSE's energy procurement, and such deficiencies may impact grid reliability.[88]

However, this very generalized handwaving does not rise to the level of specificity contemplated in Section 366.2(c)(8). There is no specific plan approved by the Commission in question, nor is there any particular explanation of how the CCA's historical RA compliance will affect any such plan. The Commission's defense has no basis.

V. THE DECISION NEEDLESSLY DISCRIMINATES AGAINST CCAS WHEN OTHER, EVEN-HANDED RA ENFORCEMENT ALTERNATIVES ARE AVAILABLE UNDER SECTION 380

The Decision also violates Section 380, needlessly discriminating against CCAs when other less restrictive solutions are available. Section 380(e) requires the Commission to apply its RA program rules even-handedly, by "implement[ing] and enforc[ing] the resource adequacy requirements established in accordance with this section in a nondiscriminatory manner." Section 380(e) requires that "[e]ach LSE shall be subject to the same requirements for [RA]…." In addition, Section 380(b)(4) requires the Commission to "minimize enforcement requirements." Despite these clear directives, the Decision fails to exercise its enforcement powers even-handedly and fails to minimize enforcement requirements despite the availability of less restrictive measures.

The Commission has not applied its new "cure" for RA noncompliance even-handedly to all LSEs. While the Decision applies the New Rule to CCAs and ESPs, it excludes their retail competitors, the IOUs. The Decision attempts to justify this exclusion by pointing to the IOUs' role as POLR.[89] While exempting the IOU in its role as POLR makes sense – the whole point of

[88] Decision at 36-37.
[89] *Id.* at 38-39.

the POLR is to serve customers other LSEs are no longer serving – the Decision misses a critical point: POLR is only one role among others served by the IOUs.

Beyond the narrow role of POLR, the IOUs, like CCAs and ESPs, serve their own load and are responsible for their RA requirements. SCE and PG&E also serve as Central Procurement Entities (CPEs), bearing responsibility to procure all local RA capacity for all LSEs. The Decision does not explain why the New Rule cannot be applied to the IOUs in these roles.

Moreover, even if there were good reasons to exempt the IOUs entirely from the rule, the inability to apply the rule even-handedly points to a need for a more broadly applicable tool to enforce RA requirements. At least two options fit comfortably within the scope of Section 380: penalties and cost allocation, and no doubt other solutions could be designed within the Commission's authority.

The Commission has to date enforced RA requirements using penalties, and there is no reason that this approach could not be further adapted to serve the Commission's objectives of driving RA compliance. Concerned that "penalty prices below the RA capacity prices may not incentive LSEs to meet system requirements in summer months," the Commission increased penalties in 2020 from $6.66/kilowatt (kW) -month to $8.88/kW-month. [90] In 2021, finding that the "current RA penalty structure does not adequately discourage LSEs from incurring repeated deficiencies,"[91] the Commission added a multiplier point system with increasing penalty levels for repeated deficiencies.[92] Indeed, D.23-06-029 clarifies the operation of the point system.[93]

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90 D.20-06-031, *Decision Adopting Local Capacity Obligations for 2021-2023, Adopting Flexible Capacity Obligations for 2021, and Refining the Resource Adequacy Program*, R.19-11-009 (June 25, 2020), at 60-61: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M342/K083/342083913.PDF .

91 D.21-06-029, *Decision Adopting Local Capacity Obligations for 2022-2024, Flexible Capacity Obligations for 2022, and Refinements to the Resource Adequacy Program*, R.19-11-009 (June 24, 2021), at 59: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603561.PDF.

92 *Id.*, OP 16 at 79.

93 Decision at 62.

Improving the existing penalty structure – by raising RA penalties further or accelerating the multiplier effect until the penalty system actually serves its function – seems the most logical course rather than "double penalizing" CCAs by applying penalties and the New Rule. As it stands, the Commission now enforces RA through a penalty structure that is, by their own admission, ineffective.

Beyond penalties, Section 380 also authorizes the Commission to address cost shifting between customer classes in another way. Section 380(b)(3) permits the Commission to "equitably allocate the cost of generating capacity and demand response" in a manner that prevents cost shifts. As set forth above, the Decision justifies its restriction on CCA expansions based on a finding that LSE RA deficiencies result in cost shifts.[94] If the Commission's "cost shift" finding is valid, the Commission should not be restricting CCA expansion as an enforcement tool but should rather utilize its existing and express authority to allocate the cost of "shifted" generation capacity.

The Commission has two central obligations in exercising its enforcement powers pursuant to Section 380(e). It must exercise them "in a nondiscriminatory manner" and "minimize enforcement requirements." D.23-06-029 fails to meet either obligation in adopting the expansion restriction for CCAs and ESPs. Moreover, the Commission ignores the clear "cure" for cost shifting provided by Section 380: cost allocation. The Decision's exercise of its enforcement powers to prevent CCA expansion exceeds the Commission's jurisdiction under Section 380, and results in the Commission not acting in accordance with law.

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[94] *Id.*, FOF 6, at 130.

VI. THE COMMISSION ABUSES ITS DISCRETION AND FAILS TO ACT IN THE MANNER REQUIRED BY LAW BY MAKING FINDINGS THAT ARE UNSUPPORTED BY THE RECORD

The Decision's findings on grid reliability in support of its New Rule are conclusory and unsupported by the record. The Commission summarily rendered its findings not only without support and reasoning but in the face of contrary evidence. RA is transacted in a complex, bilateral market under FERC jurisdiction warranting significantly greater analysis than the Decision affords. The Decision's superficial, unstudied conclusions cannot form the basis of a reasonable decision and, instead, constitute an abuse of its discretion, and a failure to act in the manner required by law.

A. The Commission Errs in Summarily Concluding that Compliant LSEs are Subsidizing Deficient LSEs' Energy Procurement

The Decision justifies its New Rule based on the purported impacts LSE deficiencies have on other LSEs. Finding of Fact 6 provides: "LSEs that are deficient in their RA obligations result in reliance on other LSEs' procurement activities and cost-shifting." [95] The Decision attempts to support this Finding of Fact with two conclusory statements unsupported by any explanation or evidence.

First, the Decision concludes:

> [I]f one LSE fails to contract for resources to serve its own load, the customers of other LSEs that did accomplish such forward contracting are effectively subsidizing the deficient LSE's energy procurement, and such deficiencies may impact grid reliability.[96]

Nothing in the decision explains how or the extent to which such a subsidy occurs. The Decision fails to identify any direct evidence of a subsidy.[97] The deficient LSE by definition did not

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[95] *Id.*, FOF 6 at 130.
[96] *Id.* at 37.
[97] "Subsidize" means "to purchase the assistance of by payment of a subsidy: *Merriam-Webster Dictionary.*

purchase the RA, so other LSEs are not "subsidizing" the deficient LSE's procurement. Neither do other LSEs subsidize the deficiency by procuring backstop resources to account for the deficiency; indeed, backstop responsibility lies with the California Independent System Operator (CAISO) under its FERC-regulated tariff.[98] Under the tariff, the CAISO has the authority to procure RA capacity to cure the deficiency and charge the cost of the backstop to the deficient LSE.

Second, the Decision concludes that:

> LSEs that are deficient in their RA obligations result in leaning on other LSEs' procurement activities and impairing grid reliability by failing to secure resources to support their existing customer base.[99]

The decision does not define "leaning" nor explain how it occurs. Other LSEs procure only for their own customers, and all LSEs, including deficient LSEs, contribute to procurement of additional resources as "excess Planning Reserve Margin" by paying for it through the Cost Allocation Mechanism.[100] Similarly, all taxpayers pay for the costs of the DWR Strategic Reliability Reserves to provide emergency reserves.[101] Other LSEs do not procure capacity to fill a deficiency by the deficient LSE. As CalCCA pointed out in its Comments on the Proposed Decision resulting in D.23-06-029 and the New Rule, if there is "leaning," the Commission caused it by failing to rely on existing regulatory mechanisms intended to solve this problem.[102] Had the Commission simply relied on the established backstop process, the CAISO under a

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98 CAISO Tariff Section 43A - Capacity Procurement Mechanism as of August 15, 2022: http://www.caiso.com/Documents/Section43A-CapacityProcurementMechanism-asof-Aug15-2022.pdf.

99 Decision at 37-38.

100 *Id.* at 25.

101 Cal. Pub. Res. Code § 25793(a).

102 *See California Community Choice Association's Comments on the Proposed Decision*, R.21-10-002 (June 14, 2023), at 6: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M511/K502/511502590.PDF.

FERC jurisdictional tariff would have procured any necessary resources and allocated the costs directly to LSEs deficient in their RA obligations.[103]

The Commission's findings and conclusions pointing to leaning or subsidies are not only unsupported, but also incorrect. The Commission's repeated conclusory assertions regarding such leaning or subsidies do not make them true – the Commission is required to justify such assertions and findings with reasoned evidence and support. The Decision's complete lack of such evidence and support of Finding of Fact 6 and other findings and conclusions concerning the existence of leaning or subsidies constitutes an abuse of discretion, and a failure of the Commission to act in accordance with law.

B. The Commission Errs in Summarily Concluding that Allowing LSEs Deficient in Meeting RA Requirements to Expand or Otherwise Take on New Customer Load is Detrimental to Grid Reliability

The abuse of discretion highlighted in Section VI.A above is exacerbated by the Commission's conclusion that "[a]llowing LSEs that cannot meet their existing RA obligations to expand their territory or to otherwise take on new customer load is detrimental to grid reliability."[104] Once again, the Commission has failed to connect the dots; it does not explain the connection between an LSE's deficiency and grid reliability, and ignores contrary evidence.

The Commission provides no response to important points raised by CalCCA in the RA Rulemaking on this issue. First, an expansion only moves customers from one LSE to another and does not alter the demand or supply for RA capacity. [105] The LSE losing customers has a lower need for RA capacity, while the LSE gaining customers has an increased need, with a net

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103 CAISO Tariff Section 43A.8: https://www.caiso.com/Documents/Conformed-Tariff-as-of-May1-2023.pdf.

104 Decision, FOF 6 at 130.

105 *See California Community Choice Association's Comments on Assigned Commissioner's Amended Scoping Memo and Ruling*, R.21-10-002 (Feb. 24, 2023), at 25: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M502/K756/502756803.PDF.

zero effect on demand. Likewise, it has no effect on the supply available to meet California's energy needs. Second, even if an LSE's individual deficiency were to impact grid reliability, the CAISO has the authority to mitigate that impact by backstopping the deficiency under its tariff and imposing the associated costs on the deficient LSE.[106]

The Decision fails to address these points and to connect the dots between a single LSE's RA compliance deficiency and grid reliability. The Decision's lack of evidence and reasoning to support its finding regarding grid reliability constitutes an abuse of discretion by the Commission, as well as a failure to act in accordance with law.

VII. CONCLUSION

For the foregoing reasons, the Commission should grant rehearing to correct each of the legal errors specified in this Application for Rehearing of Decision 23-06-029.

Respectfully submitted,

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July 26, 2023

[106] CAISO Tariff Section 43A.2.3 and 43A.8: http://www.caiso.com/Documents/Section43A-CapacityProcurementMechanism-asof-Aug15-2022.pdf.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future.	Rulemaking 21-06-017 (Filed June 24, 2021)

COMMENTS OF SILICON VALLEY CLEAN ENERGY AUTHORITY, PENINSULA CLEAN ENERGY AUTHORITY, SAN DIEGO COMMUNITY POWER, SAN JOSE CLEAN ENERGY AUTHORITY, SONOMA CLEAN POWER AUTHORITY, AND EAST BAY COMMUNITY ENERGY AUTHORITY RESPONDING TO QUESTIONS ON PART 1 OF THE ELECTRIFICATION IMPACTS STUDY

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July 28, 2023

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future.	Rulemaking 21-06-017 (Filed June 24, 2021)

COMMENTS OF SILICON VALLEY CLEAN ENERGY AUTHORITY, PENINSULA CLEAN ENERGY AUTHORITY, SAN DIEGO COMMUNITY POWER, SAN JOSE CLEAN ENERGY AUTHORITY, SONOMA CLEAN POWER AUTHORITY, AND EAST BAY COMMUNITY ENERGY AUTHORITY RESPONDING TO QUESTIONS ON PART 1 OF THE ELECTRIFICATION IMPACTS STUDY

Pursuant to the May 9, 2023, Administrative Law Judge's Ruling Directing Responses to Questions on Track 1 Phase 1 ("ALJ Ruling"), Silicon Valley Clean Energy Authority, Peninsula Clean Energy Authority, San Diego Community Power, San Jose Clean Energy, Sonoma Clean Power Authority, and East Bay Community Energy Authority ("EBCE")[1] (collectively, the "Joint CCAs") respectfully submit these comments responding to various questions related to Part 1 of the Electrification Impacts Study (Part 1 EIS). The Joint CCAs appreciate the opportunity to comment on this novel study and how it can be enhanced to offer insight into opportunities to minimize distribution costs.

I. RESPONSE TO QUESTIONS CONTAINED IN THE ALJ RULING

Questions 2.1:[2] The Joint CCAs generally agree with the approach undertaken by Kevala to develop their model from the premise level up versus current top-down distribution system planning processes. As Kevala noted, "Kevala took this approach to reflect that the implications of

[1] East Bay Community Energy Authority filed a Motion for Party Status on July 24, 2023.

[2] Question 2.1: Responses to comments on Part 1 Study and Utilities' responses to questions, filed on June 9, 2023.

electrification start at the address level and must be analyzed at this level to more accurately understand impacts on the distribution system. This approach enables the identification and assessment of grid impacts and costs not commonly identified through existing approaches."[3] The Joint CCAs agree that reorienting planning to be customer centered can result in identification of grid impacts that are lost in a top-down aggregated load approach. The Joint CCAs were heartened by the recognition from Pacific Gas & Electric Company and Southern California Edison that this bottoms up approach can provide useful insights into distribution planning processes to better identify where and when electrification loads can occur versus the status quo.[4]

The Joint CCAs also agree with numerous parties who highlighted the fact that the Part 1 EIS represents a bookend on potential distribution system costs under a worst case, unmitigated scenario of electrification. This contribution to the conversation is helpful in showing what unmitigated distribution system upgrade costs could look like. The preliminary work undertaken by the Public Advocates Office ("PAO") to model alternative scenarios with different assumptions demonstrates that changing underlying assumptions within the model can have enormous impacts on identified costs. PAO's work highlights the need for stakeholders to continue the conversation on which assumptions are reasonable as we move to undertake Part 2 of the EIS. Work undertaken by researchers at the University of California – Berkeley and Lawrence Berkeley National Laboratory also demonstrates that assumptions matter, finding that uncontrolled nighttime electric vehicle charging has the highest cost impacts.[5]

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[3] EIS, p. 6.
[4] See PG&E July 14th comments, pg. 1; see SCE July 14th comments, p. 1.
[5] See Can distribution grid infrastructure accommodate residential electrification and electric vehicle adoption in Northern California?, Emallah, Brockway, and Duncan, published November 9 2022, available at: https://iopscience.iop.org/article/10.1088/2634-4505/ac949c/pdf.

Question 2.2:[6] The Joint CCAs join other parties in acknowledging that current forecasting and planning horizons are too short to capture the full scope of the looming distribution system needs to meet state electrification goals. As expressed in our May 22, 2023 comments on distribution planning reform, the Joint CCAs support Kevala's recommendation of a 10-year planning horizon as a means to identify longer term distribution system needs while also balancing the risk of suboptimal planning decisions.[7] The Joint CCAs also agree that a longer forecasting horizon of 15 years is reasonable as a means to better align with current forecasting efforts like the IEPR, as noted by PG&E in their July 14th comments.[8] Extending forecasting and planning horizons will result in a more accurate view of system needs. Without an accurate view of needs, the likely result will be the IOUs having insufficient manpower and capital to meet system needs.

Question 2.4:[9] The Joint CCAs join other commenters in supporting the use of scenarios to inform forecasting and planning. We also agree with the IOUs' observation that ultimately a single plan must be created for the IOUs to execute against. While stakeholders can have a robust discussion on which scenarios are most likely and how the results of the scenarios should be incorporated into plans, avoiding dueling plans is important as a matter of practicality to distribution planning and execution. One scenario that holds promise is Kevala's suggestion at the May 17, 2023 workshop to develop a regional case study to assess whether virtual power plants ("VPPs") can be a mitigation measure.[10] As discussed in response to Question 2.5, modifying load

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[6] Question 2.2: How can utilities incorporate Part 1 Study recommendations to improve their distribution planning processes? If the Part 1 Study recommendations are not helpful, explain why and identify barriers to integrating them into utilities' distribution planning processes.
[7] See Joint CCA comments, p. 9.
[8] See PG&E Comments, p. 6.
[9] Question 2.4: Part 1 Study proposes developing scenarios for building electrification and adopting electric vehicles for Part 2 Study. Is this the best approach? What other scenarios, if any, should any future study consider? How should the study design these scenarios?
[10] See Electrification Impacts Study (EIS) Part 1 workshop slides, May 17, 2023, Slide 84 identifying "Targeted additional rooftop solar (battery paired); For Fresno and Oakland: Both residential and commercial and industrial (C&I)

to defer and prioritize the most critical upgrades could lead to significant cost savings; longer forecasting and planning horizons can support these efforts if the appropriate market mechanisms are in place. For example, EBCE has been developing and implementing VPPs in its service area to alleviate peak grid stress and offset procurement costs on a consistent daily basis[11] and is open to leveraging its experience and relationships deploying VPPs to facilitate this case study if it is located in the City of Oakland as suggested in Kevala's presentation at the May 17, 2023 workshop.

Question 2.5:[12] Ongoing evolution of distribution planning processes to unlock the value of non-wires alternatives needs to continue to support investment in the distribution system to meet electrification impacts by the investor-owned utilities ("IOUs") while also ensuring that IOU capital is deployed as efficiently as possible by bringing in private capital to support more cost-effective alternatives to wires upgrades. The IOUs simply do not have the resources necessary to fulfill their current distribution system upgrade needs as discussed in the Joint CCA's May 22nd comments.

The solution is an all "hands on deck" approach that focuses IOU investments to increase more efficient deployment of their capital where it is needed most while also allowing cost effective non-wires alternatives to be deployed to support system needs. The Joint CCAs appreciate SCE's observation that load flexibility enabled by DERs is part of the solution and that such opportunities should be considered earlier in the planning process. However, the Joint CCAs do not see this as an either-or scenario within the current DDP's Distribution Investment Deferral Framework ("DIDF") but rather a logical expansion of that process to capture more of the value DERs can provide. As discussed in our May comments on DIDF reform, the Joint CCAs support reforms that can expand opportunities for DERs to defer distribution upgrades while also enabling deeper load flexibility to

[11] EBCE's Resilient Home program coordinates a 2MW dispatch across 1,000+ customers with solar and storage systems to reduce peak load, and EBCE is currently developing an additional grid services program to cost-effectively manage peak load for a range of customer types and technologies.

[12] Question 2.5: What approach would best identify potential mitigations for specific locations to build a localized distribution planning framework? How should the distribution planning process incorporate this approach?

achieve similar goals as envisioned by SCE. A holistic, all hands on deck approach can mitigate costs to the benefit of all ratepayers. For example, the Joint CCAs highlighted how the use of the current five-year planning horizon coupled with IOU views on "forecasting uncertainty" constrains consideration of non-wires alternatives in ways other utilities around the country have not done.[13] Longer forecasting horizons coupled with robust scenario planning can help mitigate forecasting uncertainty.

The embrace of longer forecasting and planning horizons by numerous parties in comments, if carefully undertaken, can support reforming the DIDF screening process to allow more opportunities for non-wires alternatives to proceed. The Joint CCAs also supported including high voltage sub-transmission and transmission costs caused by grid needs when estimating the cost of a distribution project to identify the costs of a particular deferral opportunity more accurately so accurate comparison of cost effectiveness can occur. For this reason, the Joint CCAs support inclusion of secondary distribution costs in future studies and the distribution deferral planning process generally. The accurate way to determine the most cost-effective solution to a given grid upgrade need is to include all relevant costs so that an apples-to-apples comparison can be had of each mitigation option. The jurisdiction of the costs is simply not relevant as the effort being undertaken is to mitigate costs – how those costs are ultimately accounted for among the jurisdictions having authority over the upgrades can be undertaken in the appropriate forums.

The benefits to a more holistic DIDF framework are the ability to deploy innovative solutions that save all ratepayers money and encourage private capital to supplement IOU efforts. For example, if longer term planning forecasts show a distribution upgrade may be necessary in 5-10 years based on scenario analysis, those upgrades can be tested against potentially more cost-effective solutions such as virtual power plants. The Joint CCAs have deployed VPPs to modify

[13] See Joint CCA comments, filed May 22, 2023, p. 8-9.

load within the distribution system to achieve savings on wholesale energy costs for their customers. But VPPs are also capable of providing load modification that decreases the need for transmission and distribution system upgrades. By consistently shifting load from on-peak to off-peak periods, VPPs can affordably relieve grid stress in certain locations so that funding can be prioritized on the most critical grid investments. Time-varying rates also have a role to play in these efforts but are not always enough incentive to optimize dispatch of customer-sited DERs. Better technology is now available for automating and measuring DER dispatch. Because of these new technologies, VPPs can reduce peak load more reliably than behavioral demand response programs of the past. Customers continue to install DERs with load shifting behaviors and the recent Net Billing Tariff decision, D.22-12-056, should provide even greater signals to customers to install behind the meter storage. Not only does this growth in customer load modifying DERs mean there is greater, and growing, capacity for load shifting, but the growth also makes it easier for aggregators to guarantee a minimum amount of load shift to regulators and market operators. What's missing to fully unlock this opportunity is clear processes within the DIDF to enable such an outcome. The simple and most efficient way to reform DIDF to facilitate the use of VPPs for load modification to control transmission and distribution costs is to surface a market price for the load modification like the Total System Benefit metric developed by stakeholders which is now being utilized by MCE and other entities as distribution market operators.

Question 2.6:[14] The Joint CCAs support efforts to consider affordability and equity in discussions regarding a high DERs future. We were pleased to see Kevala incorporate electricity burden metrics within Part 1 of the EIS. We support Kevala's recommendation to use this information to "further inform future High DER proceeding activities such as staff proposals on how electricity burden can be included in the DPP and DIDF processes…as well as the Part 2

[14] Question 2.6: What additional topics should be considered in developing the scope for any Part 2 Study?

analysis to understand how upgrade costs and different mitigation strategies would affect electricity burden for different electrification scenarios."[15]

Down the road in the docket, consideration may also need to be given to how planning standards are used by distribution planners and engineers to ensure scenario planning assumptions do not stymie load modification as a tool to control T&D costs. "Worst case scenario planning" wherein an assumption is made that none of the mitigation measures will be successful could result in unnecessary grid upgrades. Clarity around planning standards and needs can help increase the efficiency of the DIDF process overall by ensuring nonwires alternatives are evaluated fairly while also ensuring load modifications, like VPPs, are utilized to their maximum extent to control distribution system upgrade costs.

II. CONCLUSION

The Joint CCAs appreciate the opportunity to offer these comments responding to party comments on the EIS and offer our views on next steps in the Study process.

DATED: July 28, 2023

Respectfully submitted,

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[15] See Part 1 EIS, p. 74.

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

Order Instituting Rulemaking to Develop a Successor to Existing Net Energy Metering Tariffs Pursuant to Public Utilities Code Section 2827.1, and to Address Other Issues Related to Net Energy Metering	Rulemaking 14-07-002
And Related Matters.	Application 16-07-015

**QUARTERLY DISADVANTAGED COMMUNITIES GREEN TARIFF
AND COMMUNITY SOLAR GREEN TARIFF PROGRAMS REPORT
APRIL 1, 2023 TO JUNE 30, 2023 FOR AND
SEMI-ANNUAL COMMUNITY SOLAR GREEN TARIFF PROGRAMS REPORT
FOR JANUARY 1, 2023 TO JUNE 30, 2023 FOR OF MARIN CLEAN ENERGY**

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop a Successor to Existing Net Energy Metering Tariffs Pursuant to Public Utilities Code Section 2827.1, and to Address Other Issues Related to Net Energy Metering	Rulemaking 14-07-002
And Related Matters.	Application 16-07-015

QUARTERLY DISADVANTAGED COMMUNITIES GREEN TARIFF AND COMMUNITY SOLAR GREEN TARIFF PROGRAMS REPORT FOR APRIL 1, 2023 TO JUNE 30, 2023 FOR AND SEMI-ANNUAL COMMUNITY SOLAR GREEN TARIFF PROGRAMS REPORT FOR JANUARY 1, 2023 TO JUNE 30, 2023 FOR OF MARIN CLEAN ENERGY

Marin Clean Energy ("MCE") submits this Disadvantaged Communities Green Tariff ("DAC-GT") and Community Solar Green Tariff ("CSGT") quarterly report in accordance with Resolution E-4999, issued June 3, 2019. Ordering Paragraph ("OP") 1(f) of Resolution E-4999 states:

> "Once an IOU has completed its first RFO or initiated customer enrollment, whichever occurs first, within 30 Calendar Days after the end of each calendar quarter, PG&E, SCE, and SDG&E shall file a report in R.14-07-002, or a successor proceeding, and serve the same report on that service list, for the previous quarter and cumulatively, with the following minimum information for the DAC-GT and CSGT programs: capacity procured, capacity online, and customers subscribed. The quarterly reports should also identify the DACs in which DAC-GT or CSGT project is located and list the number of customers participating in each program in each DAC within a utility's service territory. Finally, the quarterly reports must include the number of customers who have successfully enrolled in CARE and FERA in the process of signing up for the DAC-GT or CSGT programs."[1]

MCE herein concurrently submits this initial CSGT semi-annual report in accordance with OP

[1] Resolution E-4999, Pursuant to Decision 18-06-027, Approving with Modification, Tariffs to Implement the Disadvantaged Communities Green Tariff and Community Solar Green Tariff Programs, p. 63, OP 1(f).

1(g) of Resolution E-4999, which states:

> "Once an IOU has completed its first RFO or initiated customer enrollment, whichever occurs first, semi-annually, within 30 Calendar Days after the end of the second quarter of the year and the fourth quarter of the year, PG&E, SCE, and SDG&E shall report to Energy Division Central Files the number of income qualified customers subscribed to each CSGT project and the capacity allocated to those customers, whether a waitlist of non-income-qualified customers exists and the size of that list, and if project sponsors are receiving bill credits under CSGT projects, the size of each sponsor's subscription. In these semi-annual reports PG&E, SCE, and SDG&E shall also include the number of master-metered accounts participating in the CSGT program, and the total program capacity allocated to those master-metered accounts."[2]

As program administrators, CCAs are subject to the same reporting requirements as investor-owned utilities ("IOUs") and MCE hereby submits a quarterly report for DAC-GT and CSGT covering the period of April 1, 2023 to June 30, 2023, attached hereto as Attachment A. In addition, as this report is filed within 30 calendar days after the end of the second quarter of the year, this report also serves as the semi-annual report for CSGT under OP 1(g) of Resolution E-4999, covering the period of January 1, 2023 to June 30, 2023.

Respectfully submitted,

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July 28, 2023

[2] Resolution E-4999, p. 63, OP 1(g).

ATTACHMENT A

QUARTERLY DISADVANTAGED COMMUNITIES GREEN TARIFF AND COMMUNITY SOLAR GREEN TARIFF PROGRAMS REPORT FOR APRIL 1, 2023 TO JUNE 30, 2023 FOR AND SEMI-ANNUAL COMMUNITY SOLAR GREEN TARIFF PROGRAMS REPORT FOR JANUARY 1, 2023 TO JUNE 30, 2023 FOR OF MARIN CLEAN ENERGY

Pursuant to Decision 18-06-027 ("Decision")[3] and in accordance with Resolution E-4999,[4] Marin Clean Energy ("MCE") files this quarterly report on the Disadvantaged Communities Green Tariff ("DAC-GT") and Community Solar Green Tariff ("CSGT") programs for the period October 1, 2022 to December 31, 2022. MCE reports on the following program metrics as required by Resolution E-4999:

1. Capacity procured and online;
2. Participating customers, including breakdown by Disadvantaged Community ("DAC");
3. California Alternate Rates for Energy ("CARE") and Family Electric Rate Assistance ("FERA") enrollment.[5]

1. Capacity Procured and Online

The DAC-GT program (branded as MCE's "Green Access" program) has a capacity cap of 4.64 MW. The CS-GT program (branded as MCE's "Community Solar Connection" program) has a capacity cap of 1.28 MW.[6]

On August 27, 2021, MCE launched the first DAC-GT and CSGT solicitation, with bids due on November 19, 2021. MCE received bids for the DAC-GT program and signed PPAs to fill the total program capacity (4.64 MW). The resources are anticipated to be online by December 2023. MCE received no bids for the CSGT program in 2021, nor in 2022. MCE is holding another RFO for CSGT in the third quarter of 2023. As such, as of the date of this report MCE does not have any new capacity procured or online under either the DAC-GT or the CSGT program.

Enrolled customers under the DAC-GT program are currently being served by "interim resources" that meet the eligibility requirements of the programs in accordance with Resolution E-4999.[7] MCE is serving DAC-GT customers with solar generation from the Goose Lake project, located at 15004 Corcoran Rd., Lost Hills, CA 93249 in DAC census tract 6031001300.

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[3] Decision 18-06-027, Alternate Decision Adopting Alternatives to Promote Solar Distributed Generation in Disadvantaged Communities, issued June 22, 2018, p. 55.
[4] Resolution E-4999, p. 40 and p. 63, OP 1(f).
[5] Resolution E-4999, OP 1(f).
[6] Resolution E-4999 allocated MCE 4.31 MW for DAC-GT and 1.11 MW for CSGT (at p. 14). Subsequently San Jose Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Central Coast Community Energy declined to offer DAC-GT and CSGT programs for 2021, and their allocated capacity was redistributed equally among participating CCAs in accordance with Resolution E-5124
[7] Resolution E-4999, p. 24 and p. 63 OP 1(i), permits PAs to serve DAC-GT customers through existing eligible resources that meet all other DAC-GT program rules on an interim basis, until new DAC-GT projects are interconnected.

2. Participating Customers

The DAC-GT and CSGT programs provide a 20% bill discount to eligible customers located in DACs. DACs are defined under D.18-06-027 as communities that are identified in the CalEnviroScreen ("CES") tool as among the top 25 percent of census tracts statewide, plus the census tracts in the highest five percent of CES' Pollution Burden that do not have an overall CES score because of unreliable socioeconomic or health data.[8]

The DAC-GT program is available to residential customers who live in DACs, receive generation service from MCE, and meet the income eligibility requirements for the CARE program and/or the FERA program.[9] In MCE AL 42-E-A, MCE opted to auto-enroll eligible customers that live in one of the top 10% of DAC census tracts statewide in MCE's service area if they meet certain criteria.[10]

The CSGT program is available to residential customers who live in DACs (as defined by D.18-06-027) and receive generation service from MCE. Non-residential customers are not eligible to participate, except for the project sponsor. A solar generation project supporting the program must be located within five miles of the participating customers' census tract. At least fifty percent of a project's capacity must be reserved for low-income customers, defined as those meeting the income qualifications for either the CARE or FERA programs.[11]

Table 1 sets forth, for each program, the number of customers participating in each program to date. As noted above, MCE is still in the process of procuring solar generation for the CSGT program and as such has no participating customers to date. As noted above, participating customers under the DAC-GT program are being served by interim resources.

Table 1: Participating Customers in DAC-GT and CSGT Programs

	DAC-GT	CSGT
Customers Subscribed as of 12/31/2022	3,222	0

Table 2 indicates the number of customers participating in the DAC-GT program grouped by DAC census tract number.

[8] D.18-06-027, p. 16 and p. 96, Conclusion of Law 3.
[9] D.18-06-027, p. 51.
[10] MCE AL 42-E-A, p. 3.
[11] D.18-06-027, Section 6.5.3.

Table 2: Participating Customers in DAC-GT by DAC Census Tract

Census Tract	County	City (closest by proximity)	Count
6013377000	Contra Costa	Richmond	692
6013379000	Contra Costa	Richmond	556
6013365002	Contra Costa	Richmond	457
6013312000	Contra Costa	Pittsburg	196
6095250900	Solano	Vallejo	324
6013376000	Contra Costa	Richmond	460
6013382000	Contra Costa	Richmond	295
6095250701	Solano	Vallejo	324
Grand Total			**3,222**

3. CARE and FERA Customer Enrollments

MCE auto-enrolled its customers in the DAC-GT program. To date, no CARE/ FERA enrollment occurred as a result of the DAC-GT or CS-GT enrollment for customers in MCE's service area.

4. CSGT Semi-Annual Project Details

As indicated above, MCE received no bids in its 2022 solicitation for CSGT projects, and as a result has enrolled no customers in CSGT. As such, MCE has no project details to report at this time.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U39E) for Review of the Disadvantaged Communities – Green Tariff, Community Solar Green Tariff and Green Tariff Shared Renewables Programs.	A.22-05-022
And Related Matters.	A.22-05-023 A.22-05-024

OPENING COMMENTS OF THE JOINT COMMUNITY CHOICE AGGREGATORS AND CITY AND COUNTY OF SAN FRANCISCO ON ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENTS ON COST-EFFECTIVENESS CONSIDERATIONS

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July 31, 2023

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U39E) for Review of the Disadvantaged Communities – Green Tariff, Community Solar Green Tariff and Green Tariff Shared Renewables Programs.	A.22-05-022
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OPENING COMMENTS OF THE JOINT COMMUNITY CHOICE AGGREGATORS AND CITY AND COUNTY OF SAN FRANCISCO ON ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENTS ON COST-EFFECTIVENESS CONSIDERATIONS

I. INTRODUCTION

In accordance with the California Public Utilities Commission's ("CPUC or "Commission") *Administrative Law Judge's Ruling Setting Aside Submission of the Record to Seek Comments on Cost-Effectives Considerations,* dated June 23, 2023 ("ALJ Ruling"), Clean Power Alliance of Southern California ("CPA"), the City and County of San Francisco, acting by and through its Public Utilities Commission ("CleanPowerSF"), East Bay Community Energy ("EBCE"), Lancaster Choice Energy ("LCE"), Marin Clean Energy ("MCE"), Peninsula Clean Energy Authority ("PCE"), Pico Rivera Innovative Municipal Energy ("PRIME"), San Diego Community Power ("SDCP"), San Jacinto Power ("SJP"), and San José Clean Energy ("SJCE") (collectively, the "Joint Community Choice Aggregators" or "Joint CCAs") hereby submit these Opening Comments.

The Joint CCAs appreciate the Commission's aim to analyze the fiscal impacts of the existing green access programs ("GAPs") as well as the new community solar program proposals in this instant proceeding. The Disadvantaged Communities Green Tariff ("DAC-GT") and Community Solar Green Tariff ("CSGT") programs are unique amongst these offerings in that they *solely serve* customers located in disadvantaged communities ("DACs") and/or low-income customers. As such, the DAC-GT and CSGT programs are considered equity programs. Based on authorizing statute as well as Commission precedent, equity programs fall under different rules and requirements regarding both cost-effectiveness and cost shift than other programs geared at general-market customers (i.e. the Green Tariff Shared Renewables ("GTSR") and the proposed Net Value Billing Tariff ("NVBT")).[1]

The Joint CCAs assert that it is not appropriate to measure the cost-effectiveness of equity programs such as the DAC-GT and CSGT programs. This principle has been established in both authorizing statute as well as various Commission precedents as elaborated further in Section II below. In order to determine the cost shift associated with the DAC-GT and CSGT programs, the Commission must first define all of the benefits associated with the programs, including non-energy benefits ("NEBs"). The Joint CCAs elaborate on this issue in Section III below. Finally, the Joint CCAs address the question of whether the avoided cost calculator ("ACC") is the appropriate valuation methodology for front-of-meter ("FOM") resources in section IV.

II. IT IS NOT APPROPRIATE TO APPLY COST EFFECTIVENESS TESTS TO THE DAC-GT AND CSGT PROGRAMS

The ALJ Ruling requests that parties submit Total Resource Cost ("TRC"), Ratepayer Impact Measure ("RIM") and Program Administrator Cost ("PAC") test results for their program proposals based on the Standard Practice Manual ("SPM") and to further "adhere to previous

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1 While the NVBT must enroll 51% of low-income customers, the Joint CCAs assert that it is not an equity program as it is not targeting vulnerable customers exclusively.

Commission guidance on the application of cost-effectiveness evaluation and tests."[2] The ALJ Ruling suggests that these tests should be performed on "existing, modified, and new community renewable energy program proposals."[3] In accordance with the ALJ Ruling, the Joint CCAs reviewed the SPM as well as prior Commission decisions on the applicability and appropriateness of cost-effectiveness tests. After completing this review, the Joint CCAs believe it is not possible to apply the TRC, RIM, and PAC tests to the existing DAC-GT and CSGT programs while also adhering to the instructions of the SPM and previous Commission guidance.

While the Joint CCAs agree with the desire of determining cost-effectiveness for *new* community solar programs that are not solely serving DACs, the Commission should recognize that it is not appropriate to apply cost-effectiveness analyses on the equity-focused DAC-GT and CSGT programs. First, the application of these tests for DAC-GT and CSGT is inconsistent with prior Commission guidance on these programs specifically. Second, the application of these tests for equity programs is inconsistent with the instructions of the SPM. Finally, the application of these tests for equity programs is inconsistent with Commission guidance on equity programs broadly.

a. The Commission has Determined that Cost Effectiveness Tests Should Not be Applied to the DAC-GT and CSGT Programs.

Pursuant to Public Utilities Code Section 2827.1(b), as enacted by Assembly Bill ("AB") 327 (Perea, 2013) and D.18-06-027 (the "Decision"), the DAC-GT and CSGT programs are not intended to be evaluated based on cost-effectiveness. Specifically, the Decision notes that "the statutory criteria for the successor [net energy metering] tariff, such as the requirement to ensure that the total costs are approximately equivalent to total benefits, should not be applied in the

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2 ALJ Ruling at 3.
3 *Id*.

development of alternatives for DACs."[4] The Decision goes on to state that "[b]ecause this program serves multiple state policy goals, and is intended as an equity program to allow low-income customers and those in DACs to access solar distributed generation and clean energy on the same basis as other residential customers, we find that it is appropriate not to apply this constraint to DAC programs."[5] Instead, the Decision emphasizes the purpose of the programs is "to ensure that low-income households in DACs have similar opportunities as other households to access clean and innovative energy offerings."[6] DAC-GT and CSGT specifically are meant to "provide low-income customers with cost savings, while making renewable generation more broadly available to both homeowners and renters in single-family and multifamily housing in DACs."[7] An evaluation of these programs in line with Commission precedent should determine the success of the programs in meeting these goals.

Additionally, Public Utilities Code Section 769.3(b)(1), as enacted by AB 2316 (Ward, 2022), provides that the Commission must evaluate the performance of the existing GAPs to determine whether programs (a) efficiently serve distinct customer groups, (b) minimize duplicative offerings, and (c) promote robust participation by low-income customers.[8] This statutory guidance does not require that the Commission deviate from the DAC-GT and CSGT programs' original statutory goal of promoting the installation of renewable generation among residential customers in DACs.[9] While AB 2316 seeks the evaluation of the programs' ability to

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4 D.18-06-027 at 10.

5 *Id*. (As used in the Decision "DAC Programs" refer to the programs intended to benefit customers in DACs, with a particular focus on low-income residential customers within those communities. The new programs adopted in the Decision were the DAC – Single-family Solar Homes ("DAC-SASH") program, DAC-GT, and CSGT.)

6 *Id*. at 9.

7 *Id*. at 50.

8 Pub. Util. Code § 769.3(b)(1)(A).

9 *See* D.18-06-027; *See generally* Pub. Util. Code § 2827.1.

"efficiently" serve distinct customer groups, this does not equate to a cost-effectiveness test. As noted in the Joint CCAs' Opening Brief, the DAC-GT and CSGT programs should be considered as efficiently serving distinct customer groups if they (i) serve a specific customer group, (ii) provide access to 100% new renewable resources, and (iii) efficiently enable bill savings for low-income residential customers in DACs.[10] The performance of cost-effectiveness tests is neither necessary nor appropriate for this evaluation.

b. The Commission has Determined that Cost-Effectiveness Tests Should Not be Applied to Equity Programs.

Upon reviewing the SPM and prior Commission Decisions, the Joint CCAs conclude that it is not appropriate for the Commission, or parties, to apply cost-effectiveness tests to equity programs providing benefits to DACs.

First, as mentioned above, the Ruling specifically requests that parties submit the TRC, RIM, and PAC test results as outlined in the SPM for their program proposals. However, the SPM itself recognizes that these tests do not incorporate the correct information to evaluate equity programs, stating that "low-income programs are evaluated using a broader set of non-energy benefits that have not been provided in detail in this manual."[11] In outlining a list of potential adders to be included in the TRC, the SPM notes that low-income programs are social programs which have a separate list of benefits included in what is known as the 'low income public purpose test.'"[12] The SPM also notes that the low-income public purpose test "and the [specific] benefits associated with this tests are outside the scope of this manual."[13] It is not

10 Opening Brief of the Joint Community Choice Aggregators and City and County of San Francisco ("Joint CCAs Opening Brief") at 9.

11 SPM at 7.

12 *Id*.

13 *Id*. at 21.

appropriate to apply the TRC, RIM, and PAC tests to the DAC-GT and CSGT equity programs because these tests do not account for the benefits associated with equity programs.

Second, the Commission has recently concluded in other proceedings that cost-effectiveness metrics should not be used to evaluate equity programs, generally. In D.21-05-031, the Commission found that, within the context of Energy Efficiency ("EE") programs, the application of the TRC is not appropriate for judging equity programs.[14] In that Decision, the Commission separated the EE program portfolio into three segments – Resource Acquisition, Equity, and Market Support.[15] The Commission applied cost-effectiveness requirements only to the Resource Acquisition segment because it serves general-market customers and seeks to deliver grid benefits.[16] Specifically, the Decision states that, "while a TRC ratio appropriately compares the benefits and costs of a program targeted primarily at delivering grid benefits [in the Resource Acquisition segment], it may not be the most appropriate tool for judging whether energy efficiency funding was prudently spent on programs which support equity or market support goals."[17] The Decision further states that "[t]he benefits delivered by these types of programs are not assessed using the [cost-effectiveness tool] or ACC, and therefore other methods are necessary."[18]

The focus on equity customers driving the cost-effectiveness approach for both EE and the DAC-GT and CSGT programs rests on the same principles. As discussed in more detail below in Section III, we cannot measure what we cannot quantify, and we cannot quantify the benefits for equity participants beyond basic grid benefits. The Joint CCAs urge the Commission

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14 *See* D.21-05-031 at 14.

15 *Id*.

16 *Id*. at 53 ("Cost-effectiveness ratios shall also be calculated on only the resource acquisition portion of the portfolio…")

17 *Id*. at 14.

18 *Id*.

to recognize that the approach it has taken recently in EE programs and articulated in the SPM should apply here, these cost-effectiveness tests should not be applied to the DAC-GT and CSGT programs focused in this equity context.

III. IN DETERMINING A COST SHIFT METHODOLOGY, THE COMMISSION SHOULD WORK WITH STAKEHOLDERS TO DEFINE ALL THE BENEFITS OF THE DAC-GT AND CSGT PROGRAMS, INCLUDING NON-ENERGY BENEFITS

Question 2 of the ALJ Ruling requests that parties provide comments on how cost shift or cost impact on non-participating ratepayers of existing, modified, or new community renewable energy programs should be quantified and compared against each other.[19] Cost effectiveness, as discussed above in section II, can generally be defined as benefits over costs. General-market energy programs (like the EE Resource Acquisition programs) are typically expected to meet a cost-effectiveness threshold, measured with the TRC, of 1.0 on an ex-ante basis (i.e. indicating that costs of the program exceed benefits).[20] "Cost shift," on the other hand, is defined as the costs minus the benefits of the program. The remainder would be considered the costs of the program that are being shifted to non-participating ratepayers.

The costs of the DAC-GT and CSGT programs include the above market generation cost, customer bill discounts, and administrative and marketing fees. All of the *costs* for the DAC-GT and CSGT programs are publicly available in the Annual Budget Advice Letters submitted by each program administrator. However, a definition and calculation of the *benefits* of these equity programs has not been discussed by stakeholders and adopted by the Commission. For example, it is unclear to the Joint CCAs if the 20% discount provided to the participating customers would be considered a program benefit or a program cost (or both). Clearly from a participant's

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[19] ALJ Ruling at 3.

[20] For example, this requirements applies to the Resource Acquisition segment of the Energy Efficiency Portfolio. See D.21-05-031 in R.13-11-005.

perspective, the discount is a benefit. But from a non-participant's perspective, it might be classified as a cost.

Furthermore, the NEBs associated with the programs have not been defined but must be quantified to develop an accurate valuation of the benefits of these programs. As noted in section II.a above, the DAC-GT and CSGT programs were developed “to allow low-income customers and those in DACs to access solar distributed generation and clean energy.”[21] To accurately assess all the benefits of the DAC-GT and CSGT programs, the Commission and stakeholders must define the NEBs associated with bringing solar resources to customers in DACs (including, but not limited to, air quality impacts; increased health, safety, and comfort; reduction in customer arrearages; reduced risk of customer disconnections; local workforce development.

The SPM notes that the implementing entities, such as the Commission, “have traditionally utilized open public processes to incorporate the diverse views of stakeholders before adopting externality values and policy rules which are an integral part of the cost-effectiveness evaluation.”[22] Parties to this proceeding do not have the metrics necessary to capture the full benefits of the DAC-GT and CSGT programs at this point in time. If the Commission wishes to accurately assess the benefits of the DAC-GT and CSGT programs, it must work with stakeholders to consider and determine *all* benefits of the programs, including NEBs.

The Commission, as well as other state agencies, have dedicated a significant amount of time and attention into accurately valuing and defining NEBs within the context of other programs. For example, the California Energy Commission (“CEC”) has stated its intention to

[21] D.18-06-027 at 10.
[22] *Id*. at 7.

incorporate NEBs, including land use impacts, public health and air quality, economic impacts, and resilience, into the upcoming 2025 Senate Bill 100 report.[23] To this end, the CEC has issued a Request for Proposals to solicit support in developing and implementing approaches to evaluate the social costs and NEBs of the deployment of clean energy resources.[24] Additionally within the context of the Energy Savings Assistance ("ESA") program, the CPUC has been working to incorporate NEBs into its cost-effectiveness calculations over the past several years.[25] For example, in 2019, a study was conducted to update the NEB model for the ESA program.[26] Then, in 2021, an additional study was completed to evaluate the 2019 study, review the source data used for the NEB calculation inputs, remove duplicative NEBs, improve calculations, and redesign the NEB model for the ESA program.[27] The IOUs subsequently requested funding to conduct another ESA NEB study which is ongoing.[28] The Joint CCAs highlight these efforts to stress the importance of properly accounting for NEBs.

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[23] *See* 2025 SB 100 Report Scoping Phase: Tribal Listening Session Presentation, available at: https://www.energy.ca.gov/sites/default/files/202303/2025_SB100_Report_Scoping_Tribal_Listening_Session_ADA.pdf.

[24] *See* CEC Social Costs and Non-energy Benefits Request for Proposals available at: https://www.energy.ca.gov/solicitations/2023-07/rfp-23-801-social-costs-and-non-energy-benefits.

[25] *See* D.21-06-015 at 253 (addressing NEBs and directing the formation of a working group to "provide recommendations that will help facilitate the NEB study plan process.")

[26] *See* Skumatz Economic Research Associates, Inc. and Navigant Consulting Inc., Non-Energy Benefits and Non-Energy Impact (NEB/NEI) Study for the California Energy Savings Assistance (ESA) Program, Volumes 1 and 2, August 2019, available at: https://pda.energydataweb.com/#!/documents/2295/view.

[27] APPRISE Inc., California Energy Savings Assistance Program Non-Energy Benefits Final Report, January 2021, available at: https://pda.energydataweb.com/api/view/2471/Final%20CA%20ESA%20NEB%20Report%201-25-21_.pdf.

[28] *See* SDG&E Advice Letter 4148-E, PG&E Advice Letter 6893-E, SCE Advice Letter 4993-E, and SoCalGas Advice Letter 6111-G, March 23, 2023 (describing the process by which a ESA Working Group will recommend a process to incorporate new research into the NEBs model).

The Joint CCAs recommend that the Commission establish a Working Group process to further discuss options and proposals on how the benefits of the DAC-GT and CSGT programs, as well as newly proposed community solar programs in this proceeding, could be defined.

IV. THE ACC SHOULD NOT BE USED TO COMPENSATE FRONT OF METER RESOURCES

Question 3 of the ALJ Ruling requests party comments on whether it is appropriate for FOM resources to be compensated using values based on the ACC rather than least-cost best-fit ("LCBF") evaluation through the integrated resource planning ("IRP") process.[29] The Joint CCAs do not believe that it is appropriate to compensate FOM resources using the ACC in lieu of the existing LCBF methodology.

The ACC was developed and is currently used to "determine the primary benefits of distributed energy resources across Commission proceedings, the primary benefits being the avoided costs related to the provision of electric and natural gas service."[30] The Commission clarified that the "avoided costs determined in the Avoided Cost Calculator are the utilities' marginal costs of providing electric service to customers. Those costs can be avoided when the demand for energy decreases because of distributed energy resources, and are, thus, the benefits of using distributed energy resources."[31] In other words, the ACC was developed to value the avoided cost of FOM generation when using behind the meter ("BTM") resources.

As noted in PG&E's Reply Brief, BTM solar is sized to load (or expected load within 12 months).[32] Because of this, a customer's export and imports will "balance out such that there would be no net sale of energy by the customer," ensuring that the use of the BTM resource

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29 ALJ Ruling at 4.
30 D.22-05-002 at 3.
31 D.22-12-056 at 59.
32 Pacific Gas and Electric Company's Reply Brief at 14.

avoids the need for provision of electric service to that customer.[33] In comparison, FOM projects do not directly offset, and are not sized to, customer load. This discrepancy leaves unclear whether a FOM resource compensated with the ACC would actually deliver the purported benefits included in the ACC. For example, FOM resources use the transmission and distribution systems to deliver energy and so those avoided-cost benefits captured by the Transmission and Distribution adders in the ACC do not actually materialize for FOM resources. Therefore, it does not make sense to apply the ACC to programs that rely on FOM resources as FOM resources do not universally guarantee avoided costs associated with the reduction of the demand for energy.

V. CONCLUSION

The Joint CCAs thanks the Commission for its consideration of the matters set forth in these comments.

July 31, 2023

Respectfully Submitted,

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33 *Id*.

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

Order Instituting Rulemaking to Advance Demand Flexibility Through Electric Rates.	R.22-07-005

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING ON THE
IMPLEMENTATION PATHWAY FOR INCOME-GRADUATED FIXED CHARGES**

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July 31, 2023

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- The California Public Utilities Commission (Commission) should clarify in the context of the Income-Graduated Fixed Charge (IGFC) that any volumetric rate reductions do not refer to generation rate reductions.

- The Commission should direct the investor-owned utilities (IOUs) to begin outreach to customers regarding the IGFC before the implementation phase of the first version of the IGFC.

- The Commission should require the IOUs to include community choice aggregators (CCAs) in working groups related to IGFC implementation and marketing, education, and outreach (ME&O).

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Advance Demand Flexibility Through Electric Rates.	R.22-07-005

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING ON THE IMPLEMENTATION PATHWAY FOR INCOME-GRADUATED FIXED CHARGES

California Community Choice Association[1] (CalCCA) submits these comments in response to the *Administrative Law Judge's Ruling on The Implementation Pathway for Income-Graduated Fixed Charges*[2] (Ruling), dated June 19, 2023, and the *Email Ruling Granting Pacific Gas & Electric Company's and Southern California Edison Company's Joint Motion for Extension of Track A Deadlines*[3] (Extension Ruling), dated July 18, 2023. The Ruling requests comments on the implementation pathway for Income-Graduated Fixed Charges (IGFC) and the Extension Ruling extends the date for filing comments on the Ruling until July 31, 2023, and for filing reply comments on the Ruling until August 21, 2023.

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1 California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay 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 R.22-07-005, *Administrative Law Judge's Ruling on The Implementation Pathway for Income-Graduated Fixed Charges* (June 19, 2023): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M511/K720/511720058.PDF.

3 R.22-07-005, *Email Ruling Granting Pacific Gas & Electric Company's and Southern California Edison Company's Joint Motion for Extension of Track A Deadlines* (July 18, 2023): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M514/K216/514216810.PDF.

I. INTRODUCTION

The California Public Utilities Commission (Commission) continues to address grid reliability, conservation, energy efficiency, beneficial electrification, greenhouse gas (GHG) emissions reduction, and affordability issues in California through this proceeding. A major component of the overall Demand Flexibility goals includes the implementation of IGFCs for default residential rates by July 1, 2024, as required by AB 205.[4] The Ruling requests Comments on the IGFC implementation pathway. As the IGFC will apply to bundled and unbundled residential customers, careful and coordinated planning by the Commission, investor-owned utilities (IOUs), community choice aggregators (CCAs), and other stakeholders is essential to effectively manage the transition to this new residential rate structure. Income verification, timing of roll-out, and customer education are just a few of the important factors that stakeholders must consider during the planning and development process.

The Ruling poses questions for party comment regarding how to design the first version of IGFCs and to establish a pathway for implementing and improving IGFCs.[5] CalCCA's comments below are limited to the Ruling questions regarding: (1) eligible costs for inclusion in the IGFC and the corresponding volumetric rate reductions; (2) the need for early customer outreach in connection with implementation; and (3) the formation of working groups to inform

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4 Assembly Bill 205, Chapter 61 (2022) An act to add Article 13 (commencing with Section 16429.8) to Chapter 2 of Part 2 of Division 4 of Title 2 of the Government Code, to amend Sections 25403.2 and 25806 of, to add Chapter 6.2 (commencing with Section 25545), Chapter 7.4 (commencing with Section 25640), and Chapter 8.9 (commencing with Section 25790) to Division 15 of, and to add and repeal Section 25216.8 of, the Public Resources Code, to amend Sections 381, 739.1, 739.9, and 2827.1 of the Public Utilities Code, to add and repeal Section 17131.20 of the Revenue and Taxation Code, and to add Division 29 (commencing with Section 80700) to the Water Code, relating to energy, and making an appropriation therefor, to take effect immediately, bill related to the budget. (AB 205): https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=202120220AB205.

5 Ruling at 3.

implementation pathways. In response to these questions, CalCCA provides the following recommendations:

- The Commission should clarify in the context of the IGFC that any volumetric rate reductions do not refer to generation rate reductions;
- The Commission should direct the IOUs to begin IGFC outreach to customers before the implementation phase of the first version of the IGFC; and
- The Commission should provide the opportunity for community choice aggregators (CCA) to participate in working groups related to IGFC implementation and marketing, education, and outreach (ME&O).

II. THE COMMISSION SHOULD CLARIFY IN THE CONTEXT OF THE INCOME GRADUATED FIXED CHARGE THAT ANY VOLUMETRIC RATE REDUCTIONS DO NOT REFER TO GENERATION RATE REDUCTIONS

A. Question 1b: How should the Commission incentivize beneficial electrification and greenhouse gas emissions reductions during off-peak periods while meeting general conservation and efficiency goals? For example, should IGFC reductions from volumetric rates be applied to reduce rates during off-peak periods while maintaining existing peak period rates at the current level to continue to incentivize conservation and energy efficiency during peak periods?

The Commission should clarify that in the context of the IGFC, any volumetric rate reductions do <u>not</u> refer to generation rate reductions. AB 205 explicitly excludes generation charges from the IGFC.[6] Additional clarity is critical for stakeholders and the public to interpret the IGFC rate design correctly. As CalCCA pointed out in Reply Testimony, some IGFC proposals include generation charges, which if adopted would violate AB 205.[7] The volumetric rate reductions discussed in Question 1b of the Ruling apply to distribution-related costs that

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[6] AB 205 states that "[F]ixed charge" means any customer charge, basic service fee, demand differentiated basic service fee, demand charge, <u>or other charge not based on the volume of electricity consumed</u>." AB 205, subsection (a), amending section 739.9 of the Public Utilities Code (emphasis added).

[7] *See* Chapter 1, Section 2 of *Reply Testimony of Brian Dickman and Justin Kudo on Behalf of California Community Choice Association*, Rulemaking (R.) 22-07-005 (June 2, 2023) (CalCCA Reply Testimony), in which CalCCA argued against the inclusion of the Power Charge Indifference Amount (PCIA) and Competition Transition Charge in the IGFC: https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/R2207005/6133/510465634.pdf.

IOUs have historically recovered volumetrically but are actually fixed costs. The Commission should ensure that stakeholders understand the requirements of AB 205 regarding the exclusion of generation charges from the IGFC.

B. Question 5: What types of fixed costs should be eligible to be included in any given IGFC (Eligible Fixed Costs)? Please explain why specific types of costs should (or should not) be categorized as Eligible Fixed Costs based on legal or policy justifications.

As CalCCA stated in its Opening Brief on Statutory Interpretation,[8] as Witness Dickman stated in CalCCA's Reply Testimony,[9] and as set forth in response to Question 1b, above, the Commission must exclude all generation charges from the IGFC to comply with AB 205. The Commission must not consider any energy or capacity costs as Eligible Fixed Costs.

C. Question 6: Are there certain Eligible Fixed Costs that should be excluded from recovery through the first version of IGFCs? Would it be reasonable to simply recover a portion of Eligible Fixed Costs through the first version of IGFCs without specifying which costs are recovered?

See response to Question 5. Generation costs should not be considered Eligible Fixed Costs at any point in the development or implementation of the IGFC. So long as there is clarity that Eligible Fixed Costs do not include generation costs, CalCCA does not take a position at this time on whether it would be reasonable to simply recover a portion of the Eligible Fixed Costs through the first version of IGFCs without specifying which costs are recovered.

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8 *California Community Choice Association's Opening Brief*, R.22-07-005 (Jan. 23, 2023): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M501/K533/501533429.PDF.

9 *See supra,* n. 11.

III. THE COMMISSION SHOULD DIRECT THE IOUS TO BEGIN OUTREACH TO CUSTOMERS BEFORE THE INCOME GRADUATED FIXED CHARGE IS AUTHORIZED IN ORDER TO SUPPORT CUSTOMER ACCEPTANCE OF THE CHARGE

A. Question 8: How should the Commission apply the Electric Rate Design Principles to the design of the first version of IGFCs?

The Commission should direct the IOUs to begin IGFC customer outreach before the implementation phase of the first version of the IGFC. Electric Rate Design Principle #10 states that "transitions to new rate structures should (i) include customer education and outreach that enhances customer understanding and acceptance of new rates, and (ii) minimize or appropriately consider the bill impacts associated with such transitions."[10] To support the acceptance of the new rate structure, the Commission should not wait until the IGFC has already been authorized and is in the implementation stage to begin engaging with the public.

CCAs and their board members have already received numerous IGFC inquiries from customers. The content of these inquiries demonstrates that the implementation of IGFCs represents a significant, and potentially controversial and confusing, change for many customers because the requirement to link charges for electricity service to a customer's income is an entirely new way to structure electric rates. Therefore, it is imperative for the IOUs to begin customer outreach and education efforts as early as possible. For example, IOUs can begin by including a notice in their existing digital communications with residential customers that links to an informational webpage on the IGFC. This webpage could include information about the origination of the IGFC with AB 205, the procedural process for determining and establishing the IGFC, information on any public hearings on the IGFC, as well as provide updates as the

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[10] D.23-04-040, *Decision Adopting Electric Rate Design Principles and Demand Flexibility Design Principles*, R.22-07-005 (Apr. 27, 2023), Ordering Paragraph 1: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M507/K837/507837776.PDF.

proceeding continues. If customers are not engaged with the process that leads to the adoption of the IGFC, then it will be more difficult to gain their acceptance of the charge once it has already been adopted.

IV. THE COMMISSION SHOULD REQUIRE THE IOUS TO PROVIDE THE OPPORTUNITY FOR CCAS TO PARTICIPATE IN WORKING GROUPS RELATED TO INCOME GRADUATED FIXED CHARGE IMPLEMENTATION AND MARKETING, EDUCATION & OUTREACH

A. Question 15b: Should the Commission establish a working group and authorize funding for a third-party contractor to develop an ME&O proposal for consideration in this proceeding? If so, what should be the scope of work for the working group and contractor? When should the proposal be due?

The Commission should establish a working group that includes CCAs to develop an ME&O proposal for consideration in this proceeding. While IOUs will be implementing the IGFCs, implementation will have direct impacts to CCAs and their customers. CCAs frequently field customer inquiries related to the IOU side of the bill,[11] and the development process should involve CCAs for their awareness and input. CCAs have deep knowledge of the communities in their service area and serve as an important touch-point for customers, even for issues unrelated to CCA service. Local knowledge allows for effective customer outreach and education around changes to bills that will result from the IGFCs. However, due to the likely significant changes to customer bills resulting from the IGFC (whether increased or decreased bills), a working group compiled of stakeholders including LSEs serving retail customers (i.e., IOUS <u>and</u> CCAs) will contribute to timely, effective, and comprehensive ME&O strategies.

[11] *See* Chapter 2 of CalCCA Reply Testimony which establishes that most customer service interactions CCAs field are unrelated to CCA service, such as IOU rate transitions, Net Energy Metering true-ups, and expiration of California Alternative Rates for Energy (CARE)/Family Electric Rate Assistance (FERA) eligibility.

CCAs have no position on whether a third-party contractor should develop an ME&O proposal; however, CalCCA notes that the earlier the ME&O proposal is created with input from the working group, the better and more effective it will be.

B. Question 15d: Should the Commission establish a working group to discuss IGFC implementation issues and recommend improvements?

The Commission should also establish a working group that includes CCAs to discuss IGFC implementation issues and consider recommended improvements. For similar reasons outlined above in response to Question 15b, CCA understanding of IGFC implementation plans and mechanisms will support customer education and acceptance of the IGFC. In addition to consideration of critical features such as how income verification will work, other topics that the working group should discuss include: (1) streamlining of CARE/FERA and other income qualified program enrollment with income verification for the IGFC; (2) income bracket restructuring; (3) ensuring low-income customers realize savings as required by AB 205; (3) community engagement; and (4) consideration of input from equity experts and California community-based organizations.

V. CONCLUSION

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

Respectfully submitted,

Evelyn Kahl,
General Counsel and Director of Policy
CALIFORNIA COMMUNITY CHOICE
ASSOCIATION

July 31, 2023

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement Senate Bill 520 and Address Other Matters Related to Provider of Last Resort.	R.21-03-011

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY BRIEF

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July 31, 2023

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SUMMARY OF REPLY BRIEFS

- The California Public Utilities Commission (Commission) must reject Pacific Gas and Electric Company's (PG&E's) proposal to base the financial security requirement (FSR) calculation on two months of energy procurement;

- Southern California Edison Company (SCE) fails to recognize the inherent mismatch in timing between the Energy Resource Recovery Account (ERRA) trigger mechanism and the FSR posting that does not result in indifference;

- The Commission should reject SCE's rationale for retaining annual system average rates in the FSR calculation rather than using seasonal rates;

- The Commission should dismiss the Public Advocates Office at the California Public Utilities Commission's (Cal Advocates) opposition to incorporating future rate changes approved by the Commission in the FSR calculation;

- The Investor-Owned Utilities' (IOUs') proposal to remove the negative procurement cost offset would create a cost shift by ignoring some revenues the Provider of Last Resort (POLR) will receive;

- The Commission must reject San Diego Gas and Electric Company (SDG&E's) and Utility Consumer Action Network's (UCAN's) recommended changes to the use of surety bonds for the FSR postings;

- The Commission should adopt SCE's recommendation for the POLR to track adjustments to the re-entry fee rather than tracking actual costs;

- Cal Advocates incorrectly states that CalCCA's FSR calculation example contains an error;

- The Commission should reject the contract assignment proposals made by Cal Advocates and the Solar Energy Industries Association (SEIA) and the Large-scale Solar Association (LSA), as they are not voluntary for the Community Choice Aggregator (CCA), Investor-Owned Utility (IOU), and supplier;

- Cal Advocates, SEIA, and LSA are incorrect in assuming contract assignments are enforceable in Bankruptcy;

- SEIA and LSA are incorrect in their assumption that contract novation will result in lower costs to the POLR;

- The Commission should reject SEIA and LSA's proposal to allocate the costs of novated contracts to returning customers;

- The Commission must not evaluate proposals under Cal Advocates' false claims that the CCA model has not been stress tested;

- The Commission should reject Cal Advocates' recommendation to publicize CCA financial reporting;
- The Commission should reject financial reporting requirements proposed by SCE, Cal Advocates, and SDG&E that are not based upon well-defined triggers that demonstrate a need for Commission monitoring;
- Parties' recommendations to require continual financial reporting by all CCAs regardless of financial situation are unnecessary and duplicative;
- The Commission should use Debt Service Coverage Ratio rather than the Cal Advocates-recommended Current Ratio as a trigger for financial reporting;
- The Commission should reject SDG&E's proposal to require all CCAs to obtain a credit rating;
- The Commission should reject SDG&E's proposal to institute a financial review group; and
- The Commission should reject the Small Business Utility Advocates' (SBUA) recommendation that returning customers remain on POLR service as long as it takes for the POLR rate to merge into the default service or for a new CCA to assume responsibility for the load.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement Senate Bill 520 and Address Other Matters Related to Provider of Last Resort.	R.21-03-011

CALIFORNIA COMMUNITY CHOICE ASSOCIATION
REPLY BRIEF

Pursuant to Rule 13.12 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure, and the schedule set forth in the *Assigned Commissioner's Amended Scoping Memo and Ruling*[1] (Ruling*),* dated June 19, 2023, the California Community Choice Association[2] (CalCCA) submits this Reply Brief in response to Parties' Opening Briefs.[3]

I. INTRODUCTION

In its Opening Brief, CalCCA made a number of recommendations on the definition of Provider of Last Resort (POLR) service, POLR procurement, contract assignment, the Financial Security Requirement (FSR) calculation – including the individual components of the calculation and measures to adjust the FSR to account for risk, and financial monitoring. CalCCA continues

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[1] *Assigned Commissioner's Amended Scoping Memo and Ruling*, Rulemaking (R.) 21-03-011 (June 19, 2023): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M511/K719/511719405.PDF.

[2] California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay 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] All references herein to Parties' Opening Briefs refer to the Opening Briefs filed on July 10, 2023, in this proceeding (R.21-03-011).

to support these recommendations made in its Opening Brief. In response to Parties' Opening Briefs, CalCCA provides herein the following additional comments and recommendations:

- The Commission must reject Pacific Gas and Electric Company's (PG&E's) proposal to base the FSR calculation on two months of energy procurement;
- Southern California Edison Company (SCE) fails to recognize the inherent mismatch in timing between the Energy Resource Recovery Account (ERRA) trigger mechanism and the FSR posting that does not result in indifference;
- The Commission should reject SCE's rationale for retaining annual system average rates in the FSR calculation rather than using seasonal rates;
- The Commission should dismiss the Public Advocates Office at the California Public Utilities Commission's (Cal Advocates') opposition to incorporating future rate changes approved by the Commission in the FSR calculation;
- The Investor-Owned Utilities' (IOUs') proposal to remove the negative procurement cost offset would create a cost shift by ignoring some revenues the POLR will receive;
- The Commission must reject San Diego Gas and Electric Company (SDG&E) and Utility Consumer Action Network's (UCAN's) recommended changes to the use of surety bonds for the FSR postings;
- The Commission should adopt SCE's recommendation for the POLR to track adjustments to the re-entry fee rather than tracking actual costs;
- Cal Advocates incorrectly states that CalCCA's FSR calculation example contains an error;
- The Commission should reject the contract assignment proposals made by Cal Advocates and the Solar Energy Industries Association (SEIA) and the Large-scale Solar Association (LSA), as they are not voluntary for the Community Choice Aggregator (CCA), Investor-Owned Utility (IOU), and supplier;
- Cal Advocates, SEIA, and LSA are incorrect in assuming contract assignments are enforceable in Bankruptcy;
- SEIA and LSA are incorrect in their assumption that contract novation will result in lower costs to the POLR;
- The Commission should reject SEIA and LSA's proposal to allocate the costs of novated contracts to returning customers;

- The Commission must not evaluate proposals under Cal Advocates' false claims that the CCA model has not been stress tested;

- The Commission should reject Cal Advocates' recommendation to publicize CCA financial reporting;

- The Commission should reject financial reporting requirements proposed by SCE, Cal Advocates, and SDG&E that are not based upon well-defined triggers that demonstrate a need for Commission monitoring;

- The Commission should reject Parties' recommendations to require continual financial reporting by all CCAs regardless of financial situation are unnecessary and duplicative;

- The Commission should use Debt Service Coverage Ratio rather than the Cal Advocates'-recommended Current Ratio as a trigger for financial reporting;

- The Commission should reject SDG&E's proposal to require all CCAs to obtain a credit rating;

- The Commission should reject SDG&E's proposal to institute a financial review group; and

- The Commission should reject Small Business Utility Advocates' (SBUA) recommendation that returning customers remain on POLR service as long as it takes for the POLR rate to merge into the default service or for a new CCA to assume responsibility for the load.

II. FINANCIAL SECURITY REQUIREMENTS AND RE-ENTRY FEES

A. The Commission Must Reject PG&E's Proposal to Base the FSR Calculation on Two Months of Energy Procurement

PG&E continues to propose that the CCA's FSRs provide the POLR with "upfront and immediate access" to two months' forecasted energy costs with no revenue offset.[4] PG&E's liquidity issues – the apparent driver of this proposal – stem from a billing lag resulting from the timing of when California Independent System Operator Corporation (CAISO) payments are due relative to when PG&E receives POLR customers' payments on their bills.[5] SCE, who had not

4 PG&E Opening Brief at 11.
5 PG&E Opening Brief at 16-17.

weighed in on PG&E's proposal up until this point, indicated that "SCE finds PG&E's proposal reasonable assuming the Commission decides to address POLR liquidity needs through the CCA FSR rather than through other regulatory mechanisms. The existing CCA FSR is designed as an indifference mechanism for customers in a mass involuntary return, not as a means of ensuring POLR liquidity."[6] The Commission must reject PG&E's proposal, as PG&E has not demonstrated a need to radically change the purpose of the FSR, completely ignore the revenue side of the equation, and create FSR postings so high that they negatively impact CCA operations.

PG&E's proposal assumes mass involuntary customer return will occur ***and*** that the POLR will not be able to finance any of the costs associated with the billing lag between when CAISO payments are due and when PG&E would receive customer payments. The Commission should not make these assumptions. PG&E does not justify the assertion that it will not be able to pay for or finance these costs in the event of mass involuntary customer return. While PG&E explains its estimated incremental procurement costs to provide two months of energy to returning customers of approximately $200 million to $400 million for 2020-2022, respectively,[7] this information does not confirm that the POLR will be unable to find adequate credit facilities upon customer return to cover that amount. Further, PG&E's estimation assumes that PG&E would need to provide energy to ***all*** CCA customers simultaneously, but PG&E provides no evidence to support that the full return of all CCA customers in its service area is the type of event that should be anticipated.

PG&E ignores that if the POLR does not have the liquidity to cover the re-entry costs immediately, the liquidity crunch will be relatively short-lived. In a period of rising energy prices, the IOU will have increased liquidity, rather than reduced liquidity, resulting from higher energy

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6 SCE Opening Brief at 45.

7 PG&E Opening Brief at 14-16.

prices it receives for its resources than are reflected in customer rates. The revenues for these resources will come from the CAISO and will be made available to the POLR on the same time frame as the bills for the incremental load assumed.

As SCE points out, the FSR is not designed to ensure POLR liquidity. Decision (D.) 18-05-022, establishing Re-Entry Fees and FSRs for CCAs, found that, "[t]he purpose of the [FSR] statute appears to be more about basic financial security – ensuring that money is available – rather than liquidity."[8] If PG&E's concern is "liquidity" – having funds available when needed – the IOU should rely on short-term borrowing. Requiring a CCA to post security for a return on the basis of liquidity means that the CCA customers will pay the financing cost of that instrument regardless of whether the customers are returned to POLR service. Instead, using a balancing account with financing charges for the required liquidity would be less expensive and result in costs to provide liquidity incurred only if customers are actually returned to the IOU.

PG&E indicates that its proposal is necessary to "ensure uninterrupted electrical service to returned customers in all circumstances."[9] If PG&E and the Commission see there is a risk that PG&E cannot effectively serve its role as POLR without CCAs fronting two months of energy costs, then the Commission should move expeditiously to the second phase of this proceeding. The second phase must then focus on identifying a non-IOU entity whose financial capability is not threatened in the manner that PG&E is concerned. Absent that assessment, the Commission should continue with its plans to focus on modifications to the individual components of the FSR calculation to make them more accurate in this phase. It can then

[8] D.18-05-022, *Decision Establishing Re-Entry Fees and Financial Security Requirements for Community Choice Aggregators*, R.03-10-003 (June 7, 2018): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M215/K726/215726275.PDF.

[9] PG&E Opening Brief at 11.

evaluate the need for an insurance pool to address PG&E's concern in the second phase of this proceeding and evaluate whether another entity should serve as the POLR.

B. SCE Fails to Recognize the Inherent Mismatch in Timing between the ERRA Trigger Mechanism and the FSR Posting That does not Result in Indifference

SCE recommends:

> …to truly fulfill the directives of Section 394.25(e) and protect customers for the risks and costs associated with CCA mass involuntary returns, the CCA FSR and Re-Entry Fees must be consistently enforced, and they have not been enforced in the recent past. For example, in 2022 the Commission declined to enforce CCA FSR amounts in SCE's service area that were significantly higher than the more common minimum FSR amounts, which occurred because forward energy prices were significantly higher over the six-month forward period.[10]

SCE ignores an inherent mismatch in the timing of FSR calculations and posting and the ERRA trigger mechanism. The FSR calculations and postings are based upon forecasts, while the ERRA trigger mechanism is retrospective. In SCE's 2022 example, the calculated FSRs were based on high summer forwards. Despite these high forwards, the IOU did not update their retail rates. If the high forwards materialize into high actuals, then it is highly likely the IOU will file an ERRA trigger as the current retail rates were insufficient to cover the higher prices in the energy market – which SCE did in its example. Because FSR calculations/postings and ERRA triggers happen at different points in time, the Commission asks CCAs to front those costs but does not ask IOU customers to react to those costs until after the fact. This mismatch does not meet the Commission's statutory requirements for indifference.[11] That is, any customer that has

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[10] SCE Opening Brief at 26 (citations omitted).

[11] D.05-12-041, *Decision Resolving Phase 2 Issues on Implementation of Community Choice Aggregation Program and Related Matters*, R.03-10-003 (Dec. 15, 2002), at 26: "The statute requires that we set the [Cost Responsibility Surcharges] so as to make bundled customers indifferent to the CCA's offering of service.": https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/52127.PDF.

to immediately bear the financing costs of expected future costs would rather choose to be a bundled load customer where that uncertainty is replaced with after-the-fact certainty. Not only is the customer not indifferent to the uncertainty aspect of forecast versus actual costs, but they are not indifferent to paying now versus paying later even if there were no uncertainty.

A potential solution to make customers truly indifferent between CCA service and bundled service would be to evaluate the potential for an ERRA trigger at the time that the FSR is calculated based upon the estimated energy forwards, RA prices, and Renewable Portfolio Standard (RPS) prices. The IOUs would not be required to change retail rates under this mechanism but would need to evaluate a retail generation rate that is more indicative of the likely rate that would be paid by returning load given the estimate that under the current rates, the IOU would under-collect their ERRA balance. Placing the costs of energy, RA, and RPS on a forecast basis and making it consistent with the rates that the IOU would anticipate charging if those costs came true (i.e., a forecast basis) would be more reflective of the actual balance of revenues and costs and the actual securitization necessary. Conceptually, this is very similar to the point that CalCCA has made that if energy costs are calculated on a summer forecast, then the retail rates applied should be for summer rates also. Here, the difference is that the generation rate should reflect what is necessary to recover the forecast costs instead of the present rate which may or may not be capable of recovering the IOUs costs but are likely to cause an ERRA Trigger filing.

C. The Commission Should Reject SCE's Rationale for Retaining Annual System Average Rates in the FSR Calculation Rather than Using Seasonal Rates

SCE recommends the Commission reject CalCCA's proposal to use seasonal rates to calculate generation revenues component of the FSR because "CalCCA identifies no reasonable means of adjusting the generation costs for seasonality."[12] No party has put forth a reasonable means to estimate seasonal generation costs because, as CalCCA explained,[13] it is unclear whether it is possible given how the existing PCIA market price benchmark is formulated and how contracting is performed in annual or multi-year periods.

SCE states:

> The IOUs and Cal Advocates point out that introducing a seasonality adjustment on the revenues side of the CCA FSR and Re-Entry Fees calculation without adjusting for the seasonality of RA prices on the cost side, as CalCCA proposes, would be a disproportionate change because it would reflect more revenues and less costs in the summer, despite the fact that summer generation rates are higher because the costs of energy and capacity are higher in the summer.[14]

SCE fails to recognize that it is the current FSR calculation, not CalCCA's proposal, that disproportionately adjusts for seasonality by including seasonal energy costs, through the use of an ICE forward specific to the forecast six-month period, but no other seasonal measures including those related to revenues. The result of doing so is that the vast majority of the FSR *costs* are seasonally differentiated but none of the FSR *revenues* are seasonally differentiated. CalCCA estimates that energy costs make up 85 percent of the cost component of the FSR, while RA costs only make up 10-14 percent.[15] Reflecting seasonal rates in the FSR calculation would remedy this existing misalignment.

The Commission should not condition the adoption of seasonal rates on the adoption of seasonal generation costs. Instead, the Commission should reflect seasonal values where such information is readily available and reasonably accurate: in the IOU rates used to calculate forecast

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12 SCE Opening Brief at 34-35.
13 CalCCA Opening Brief at 29.
14 SCE Opening Brief at 35 (footnote omitted).
15 This calculation is based upon the data submitted by the IOUs and CalCCA within the April 4, 2023, workshop to provide FSR calculators for a sample calculation.

revenues, and in the forwards used to calculated forecast energy costs. It should not do so where those values are not supported by evidence sufficient to provide a reasonably accurate value.

D. The Commission Should Dismiss Cal Advocates' Opposition to Incorporating Future Rate Changes Approved by the Commission in the FSR Calculation

Cal Advocates is the only party that opposes CalCCA's proposal to incorporate future Commission-approved rate changes in the revenue component of the FSR calculation. It argues that because the IOUs only incorporate approved rate changes in their ERRA forecast and ERRA update applications, including future rate changes in the FSR calculation would result in greater inaccuracy and less transparency.[16] The Commission should dismiss Cal Advocates opposition and adopt CalCCA's proposal to incorporate future Commission-approved rate changes in the FSR.

CalCCA's proposal would only incorporate future rates if those rates were known with certainty at the time the calculation is made. Reflecting the most current rates ensures that the forecast costs and offsetting revenues are reasonably aligned. Omitting known rate information from the FSR calculation would make it less accurate, because the calculation will be based on outdated rates that will not actually be in place during the period covered by the FSR. For this reason, the Commission should reject Cal Advocates' arguments that including Commission-approved future rates in the FSR calculation will make the calculation less accurate and less transparent.

E. The IOU's Proposal to Remove the Negative Procurement Cost Offset Would Create a Cost Shift by Ignoring Some Revenues the POLR Will Receive

SCE recommends the Commission adopt the IOUs' proposal to remove the negative procurement cost offset of administrative costs in the CCA FSR because administrative costs

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[16] Cal Advocates Opening Brief at 10.

associated with switching CCA customer service accounts to the POLR are recovered through service fees rather than IOU procurement rates.[17] The Commission should reject this proposal.

Prohibiting excess procurement revenues from reducing administrative costs would create a cost shift by allowing the CCA's payment of the Re-Entry Fee to reduce the costs bundled customers pay through the ERRA. Any projected revenues greater than the Energy, RA, and RPS costs would go to the ERRA to pay down the balances of both returning load and existing bundled load rather than paying down the costs of the returning customers administrative fees. The Commission should not allow this cost shift to occur.

Whether the costs are recovered through service fees or procurement rates, if SCE's recommendation is approved, the CCA would pay for both the procurement costs and administrative costs while bundled load benefits from any overpayment of ERRA costs. If revenues received from returning customers are forecasted to fully cover all costs, a CCA should not be required to post in excess of the minimum FSR. As such, CalCCA recommends the Commission reject SCE's proposal and retain the negative procurement cost offset.

F. The Commission Must Reject SDG&E and UCAN's Recommended Changes to the Use of Surety Bonds for the FSR Postings

Two parties recommend changes to the FSR to address the IOU concerns around the liquidity of surety bonds. SDG&E recommends the Commission "limit use of the bond to a *de minimus* portion of the FSR in order to preserves [sic] necessary liquidity for the POLR."[18] UCAN recommends increasing the FSRs for CCAs who rely on surety bonds to reflect the "issue of lack of liquidity of surety bonds."[19] The Commission must reject these recommendations for the reasons described below.

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[17] SCE Opening Brief at 33-34.
[18] SDG&E Opening Brief at 20.
[19] UCAN Opening Brief at 9.

1. The Statute Clearly Places No Restriction on How Much of the FSR can be Covered by a Surety Bond

SDG&E suggests its recommendation to limit the use of the bond to a "de minimus portion" of the FSR could be consistent with the statute because Section 394.25(e) "does not require the *entire* amount of the FSR be secured through a bond."[20] The Commission must reject this argument. As the Commission previously determined, the statute is clear that CCAs can use surety bonds for their FSR postings.[21] The governing statute has not changed and continues to permit the use of a bond. Importantly, the statute does not put *any* limits on the amount of the FSR that can be covered by surety bonds, and given the clarity of the statutory language it is impermissible to impute a limitation. The Commission cannot limit the use of surety bonds for FSR postings. Doing so would be inconsistent with the statue.

2. There is No Evidence Supporting UCAN's Suggestion that the FSR be Increased if CCAs use a Surety Bond for their FSRs

UCAN's proposal to increase the FSRs for CCAs who rely on surety bonds is an attempt to address concerns expressed by the IOUs and summarized in D.18-05-022:

> Collecting on a surety bond is similar to collecting on an insurance claim, where a litigious and delayed process for resolving a claim is not unusual. This is problematic, particularly when the IOU may need immediate liquidity to procure resources to serve the involuntarily-returned CCA customers, and accounts for why surety bonds are not used in the energy procurement business.[22]

The Commission expressly rejected this argument in D.18-05-022 when implementing the statute with respect to CCAs:

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[20] SDG&E Opening Brief at 20.

[21] *See* D.18-05-022 at 9 (confirming that the use of surety bonds is consistent with the express statutory language).

[22] *Id.*at 9 (citation omitted).

> The purpose of the statute appears to be more about basic financial security – ensuring that money is available – rather than liquidity. The fact that surety bonds may not be commonly used for other purposes in the energy procurement business does not control in this context, where there is express statutory language. Accordingly, we approve the use of surety bonds as FSR for CCAs.[23]

The IOUs' supposition was not sufficient when raised before the Commission previously, and it is not sufficient now to remove surety bonds as an option. It is also not sufficient justification for increasing the FSR for CCAs that use surety bonds. Even if the purpose of the FSR was to provide liquidity, increasing the FSR does nothing to resolve the IOUs' perceived issues with immediate liquidity associated with surety bonds. For these reasons, the Commission should reject UCAN's proposal.

G. The Commission should Adopt SCE's Recommendation for the POLR to Track Adjustments to the Re-Entry Fee Rather than Tracking Actual Costs

SCE supports the Energy Division Staff Proposal to require the IOUs to track adjustments to the Re-Entry Fees rather than tracking actual costs.[24] CalCCA also supports the Energy Division Staff Proposal. The Energy Division Staff Proposal would ensure Re-Entry Fees and FSRs are set consistently.

In the complicated world of the IOU Procurement Plans, it is difficult to imagine how the POLR could identify all costs (associated with energy, RA, and RPS) specific to returning customers. For example, if the IOU finds it has a long RA position in at least one of the months, it will not buy RA, and use a resource in the existing IOU portfolio instead. It would not be possible to determine which resource in its existing portfolio it used for the returning customers. This difficultly in precisely tracking costs is why the FSR uses a benchmark. As all costs

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23 *Id.*

24 SCE Opening Brief at 57-58.

associated with customer return cannot be successfully calculated, CalCCA supports SCE's recommendation to track adjustments to Re-Entry Fees rather than actual costs.

H. Cal Advocates Incorrectly States that CalCCA's FSR Calculation Example Contains an Error

Cal Advocates find that CalCCA's example FSR calculation presented at the April 4, 2023, workshop "contains errors" because it reduces the CCA load used to calculate forecasted energy costs by the CCA's vintaged load share of energy in the PCIA portfolio.[25] CalCCA's example FSR calculation does not include an error; it correctly reflects CalCCA's proposal to reduce the energy volumes used in the FSR calculation to remove amounts hedged through the PCIA portfolio. Using the word "error" incorrectly implies a miscalculation. Instead, CalCCA's example calculates the FSR correctly per its proposal, and Cal Advocates simply disagrees with the proposal.

III. CONTRACT ASSIGNMENT

A. The Commission Should Reject the Contract Assignment Proposals made by Cal Advocates and SEIA and LSA, as They Are not Voluntary for the CCA, IOU, and Supplier

SEIA and LSA propose contract novation in which the POLR takes on all rights and obligations under the deregistering CCA's contract.[26] Cal Advocates propose the POLR have a right of first refusal (ROFR) over the returning CCA's contracts.[27] CalCCA continues to recommend the Commission reject mandatory contract assignments for the reasons described in its Opening Brief:

- Adopting contract novation or ROFR requirements could have significant cost impacts on existing and future contracts in order to prepare for an event unlikely to occur in the first place;

25 Cal Advocates Opening Brief at 11.
26 LSA/SEIA Opening Brief at 3-5.
27 Cal Advocates Opening Brief at 19-20.

- There are existing contracts that do not contain these provisions, including long-term contracts to meet RPS requirements. To implement a new requirement would potentially mean the re-negotiation of contracts whose terms and conditions may have been set years prior;

- The IOUs do not support mandatory contract assignments because the POLR would play no role in negotiation;

- The Commission does not have clear authority under PU Code 387 to mandate contract novation or a ROFR; and

- Mandatory resource assignment presents serious legal questions in the context of bankruptcy.[28]

As SCE states, "… most parties who participate in the market – including the CCAs and IOUs – oppose mandatory contract assignments as impractical, unnecessary and unlawful because they would result in cost shifting."[29] The Commission should reject SEIA and LSA and Cal Advocates proposals for mandatory contract assignments and only adopt contract assignment rules to the extent that they are voluntary for the CCA, IOU, and supplier.

B. Cal Advocates, SEIA, and LSE are Incorrect in Assuming Contract Assignments are Enforceable in Bankruptcy

In supporting its ROFR proposal, Cal Advocates suggests that:

> …CalCCA confuses Chapter 11 bankruptcy, which covers corporate reorganization, with Chapter 9 bankruptcy, which covers CCAs and other municipalities. A federal bankruptcy court has limited authority in a Chapter 9 bankruptcy due to the Tenth Amendment and the federal law constrains the bankruptcy court from the types of interventions described by CalCCA.[30]

SEIA and LSA similarly suggest the federal bankruptcy courts have limited authority in a Chapter 9 case and therefore "…the debtor – in this case the CCA – will retain its property and operational control even after it files for bankruptcy."[31]

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28 CalCCA Opening Brief at 10-15.
29 SCE Opening Brief at 15.
30 Cal Advocates Opening Brief at 20.
31 LSA Opening Brief at 13.

Cal Advocates, SEIA, and LSA's arguments miss the point. The provision of the Bankruptcy Code that makes *ipso facto* clauses, like the proposed automatic reassignment provision, generally unenforceable in bankruptcy is expressly incorporated into Chapter 9.[32] Thus, such a clause would likely be assignable only at the election of the entity seeking bankruptcy protection – whether in Chapter 9 or Chapter 11. These parties also ignore that Chapter 9 relief is available only to a "political subdivision or public agency or instrumentality of a State."[33] While there is one example of a California CCA seeking relief under Chapter 9,[34] an IOU like PG&E is not so eligible and may only seek relief under Chapter 11. Finally, while Section 904 of the Bankruptcy Code limits the Bankruptcy Court's ability to interfere with an eligible municipality's property, revenues, and powers of governance, by electing federal bankruptcy relief the municipality subjects itself to the requirements of that chapter the Bankruptcy Code.[35]

The case that Cal Advocates cites reiterates these basic principles.[36] While the Bankruptcy Court's authority to afford interim relief in a Chapter 9 proceeding is limited by

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[32] 11 U.S.C. § 901.

[33] 11 U.S.C. § 101(40).

[34] In *Re Western Community Energy*; Bankr. C.D. Cal., Case No. 21-12821.

[35] *See County of Orange v. Merrill Lynch & Co. (In re County of Orange),* 191 B.R. 1005, 1021 (Bankr. C.D. Cal. 1996) ("By authorizing the use of chapter 9 by its municipalities, California must accept chapter 9 in its totality; it cannot cherry pick what it likes while disregarding the rest."); *see also In re City of Vallejo*, Case No: 08-26813, Dkt. No. 473, p.4:7-12 (Bankr. E.D. Cal. March 13, 2009) ("[w]hen a state authorizes its municipalities to file a chapter 9 petition it declares that the benefits of chapter 9 are more important than state control over its municipalities.").

[36] *See* Cal Advocates Opening Comments n. 106 citing United States v. Bekins, 304 U.S. 27, 54 (1938) ("The State acts in aid, and not in derogation, of its sovereign powers. It invites the intervention of the bankruptcy power to save its agency which the State itself is powerless to rescue.").

Section 904,[37] the Bankruptcy Court will ultimately be asked to confirm a plan of adjustment that provides for the municipality's reorganization on a final basis.[38]

Arguments that the proposed assignment rules are not ipso facto clauses are also misguided. The proposed regulation would impose into a contract between the CCA and a private counterparty a requirement that the counterparty terminate its relationship with the CCA and instead transact with the POLR. In the context of a CCA bankruptcy filing, this functions as *ipso facto* provision, i.e., a termination or modification of an executory contract triggered by insolvency or a bankruptcy filing.

C. SEIA and LSA are Incorrect in Their Assumption that Contract Novation will Result in Lower Costs to the POLR

SEIA and LSA suggest that mandatory contract novation "provides greater security for the financer (allowing projects to go forward) and reduces the financing costs and thus the overall costs of the contract."[39] As CalCCA explained in its Opening Brief, SEIA and LSA's assumption that contract novation will reduce financing costs may not always hold true.[40] It is unclear whether all generators or market participants would actually transact with contract assignment to the POLR as a contractual condition. Even if they were willing, all such conditions come at a cost dependent on the credit risk of both counterparties. Additionally, contract novation could be more expensive than the POLR procuring from the market depending on when the CCA entered into the contract relative to when the POLR procures for returned customers. If market conditions ease between the CCA's procurement and customer return, it could be more

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37 See, e.g., *In re City of Detroit* 841 F.3d 684 (6th Cir. 2016) (Bankruptcy Court lacks authority to enjoin chapter 9 debtor against shutting off water supply).

38 See *In re Valley Health System* (Bankr. C.D. Cal. 2010) 429 B.R. 692 (confirming chapter 9 plan of adjustment including the sale of assets, after analyzing California state law requirements).

39 LSA/SEIA Opening Brief at 6-7.

40 CalCCA Opening Brief at 10-11.

cost effective for the POLR to procure from the market rather than have the CCA's contract assigned to the POLR.

D. The Commission Should Reject SEIA and LSA's Proposal to Allocate the Costs of Novated Contracts to Returning Customers

SEIA and LSA recommend "[t]he costs of the contracts which are novated from a failed CCA to a POLR should be allocated to the customers of the CCA who are returned to the POLR to ensure that there is no cost shift between bundled customers of the POLR and the returning customers of the CCA."[41] The Commission must reject this recommendation, as it would create a fundamental shift in how the market works in a manner that puts contracting risk on customers rather than load-serving entities (LSEs). Procurement contracts are between the generator and the LSE, not the generator and the customers of the LSE. It is, therefore, the LSE that determines its risk profile associated with contracting, which contracts to take on, and how to recover costs for those contracts. The current FSR and re-entry fee mechanism is consistent with this market structure by requiring the CCA to post the FSR and pay re-entry fees associated with incremental costs. The Commission should not modify this structure as SEIA and LSA suggest by requiring contract novation and putting the risk of those novated contracts on customers.

IV. FINANCIAL MONITORING

A. The Commission must not Evaluate Proposals under Cal Advocates' False Claims that the CCA Model has not been Stress Tested

Cal Advocates claims that "[t]he CCA model in California has not yet been stress tested by an extended national recession lasting longer than a single quarter" when discussing its recommendations for financial monitoring CCAs.[42] The Commission should not let this false claim drive any findings or policy decisions in this proceeding. "Extended national recessions"

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[41] LSA/SEIA Opening Brief at 4.
[42] Cal Advocates Opening Brief at 14.

are not the only ways to stress test the CCA model. In fact, in the last few years alone, the CCA model has been stress tested in many different ways. As described in CalCCA's Opening Brief,[43] in 2022 and 2023 alone, LSEs have experienced exceptionally high summer forwards, an extreme heat event resulting in a new all-time CAISO system peak, winter electricity prices four times higher than previous years, and prolonged capacity shortfalls driving up RA costs. This all took place immediately after the COVID-19 pandemic, which necessitated providing relief to residential customers through additional time to pay off deferred energy bills and a suspension of disconnections. Throughout this extended period of stress testing, "mass involuntary returns" of CCA customers did not occur. The Commission must not evaluate the recommendations made in this proceeding under the false perception that the CCA model has not been stress tested.

B. Reject Cal Advocates Recommendation to Publicize CCA Financial Reporting

Cal Advocates suggests that the Commission should reject the Energy Division Staff Proposal for confidential treatment of CCAs' financial reporting because Joint Powers Authorities, as public agencies, are obligated to report financial metrics on a quarterly basis.[44] The Commission should reject Cal Advocates' recommendation for the same reasons CalCCA provided in its Opening Brief.[45]

First, publicizing market-sensitive information about one LSE would put that LSE at a competitive disadvantage relative to other LSEs and the LSE's counterparties who may take actions in buying from and/or selling to the CCA that they would not have if they were positioned similar to any other market participant. *Second*, a CCA triggering financial reporting will not always mean the CCA will return load to the POLR, and, therefore, there is not a clearly

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[43] CalCCA Opening Brief at 2-4.
[44] Cal Advocates Opening Brief at 16.
[45] CalCCA Opening Brief at 47-48.

defined need for publicizing the reported information. The purpose of financial monitoring should be to keep the Commission apprised of potential financial situations that *may* result in customer return if not properly addressed. The Energy Division Staff Proposal accomplishes this. *Finally*, CCAs are transparent about their financial conditions. They make their financial circumstances public in their Board packets and through links on their website and the CalCCA website. This includes data points necessary to calculate days liquidity on hand, data points necessary to calculate debt ratio, risk management policies, and ratemaking policies and changes It does not include defaults on RA contracts or non-payments to CAISO scheduling coordinators, energy and hedging contract term details, or the status of procurement contracts. Publicizing additional information including when CCAs trigger financial reporting and information submitted by CCAs pursuant to the requirements in the Energy Division Staff proposal is unnecessary and harmful to CCAs given the market-sensitive information that could be provided to other market participants. The Commission should make it explicit that: (1) an event that triggers CCA financial reporting, and (2) information submitted by a CCA pursuant to its financial reporting requirement, is confidential including from the POLR.

C. The Commission Should Reject Financial Reporting Requirements Proposed by SCE, Cal Advocates, and SDG&E that are not Based Upon Well-Defined Triggers that Demonstrate a Need for Commission Monitoring

1. Parties' Recommendations to Require Continual Financial Reporting by All CCAs Regardless of Financial Situation are Unnecessary and Duplicative

Several parties recommend the Commission require some form of financial reporting for all CCAs regardless of financial condition.[46] The Commission should reject this recommendation. While CalCCA generally supports financial monitoring and reporting to aid in

[46] Cal Advocates Opening Brief at 18, PG&E Opening Brief at 21, SCE Opening Brief at 54, and SDG&E Opening Brief at 22.

alerting the Commission of potential customer returns,[47] the Commission should focus its financial monitoring on CCAs that have a demonstrated need for it. CalCCA does not support requiring CCAs to continually report financial metrics to the Commission without hitting a trigger that indicates a need to do so. Requiring quarterly reporting for all CCAs regardless of whether a CCA has experienced a triggering event would be unnecessary.

SCE suggests that the Energy Division Staff Proposal, which CalCCA supports with modifications, lacks transparency and "relies too much on the honor system" regarding the reporting of triggering events.[48] CalCCA disagrees. Unlike profit-motivated LSEs, CCAs make their financial circumstances public, both in their Board packets and through links on their website and the CalCCA website. In addition, the Commission has important existing enforcement mechanisms that it could apply to financial reporting. Failure to report a triggering event could be considered a Rule 1 violation, meaning CCAs would be obligated to report a triggering event or face the consequences of a Rule 1 violation. Relying on existing enforcement mechanisms will ensure CCAs report upon identification of a trigger event. Therefore, rather than requiring regular reporting, the Commission should require a CCA to assess its financial metrics once every 60 days, and report to Energy Division within 10 days if it observes a trigger event.

2. Use Debt Service Coverage Ratio Rather than the Cal Advocates-Recommended Current Ratio as a Trigger for Financial Reporting

Cal Advocates recommends the Commission use Current Ratio less than 2.0 to trigger financial monitoring and not use Debt Service Coverage Ratio less than 1.0 because using Debt Service Coverage Ratio would "add unnecessary complexity and require the Commission to have deep knowledge of the debt structure of a CCA."[49] The Commission should not adopt this

47 CalCCA Opening Brief at 43-44.
48 SCE Opening Brief at 53.
49 Cal Advocates Opening Brief at 16.

recommendation. Current Ratio is a less reliable measure of financial strength than Debt Service Coverage Ratio. The Debt Service Coverage Ratio below 1.0, as proposed by Energy Division Staff, signifies losses or slim surpluses and should be used to trigger financial reporting.

3. Reject SDG&E's Proposal to Require all CCAs to Obtain a Credit Rating

SDG&E recommends the Commission require all CCAs to obtain a credit rating. SDG&E suggests such a requirement would provide the Commission with an "objective means of evaluating CCAs' financial condition."[50] The Commission should dismiss SDG&E's recommendation that all CCAs must pursue a compulsory credit rating because (1) it would place an undue burden on CCAs and (2) other financial monitoring mechanisms better fit the Commission's needs in the context of customer return to the POLR.

The Commission should not require all CCAs to obtain credit ratings given the undue burden it would place on smaller or newly forming LSEs. Obtaining a credit rating by an independent agency is costly and requires an extreme amount of time and effort that may be too burdensome for smaller or newly formed LSEs. In addition, forcing newly launched CCAs to get credit ratings before they are ready and have established an operating history is very likely to increase the costs for new CCAs both in (1) staff time and direct costs to work with rating agencies; and (2) higher procurement costs across the board.

Requiring credit ratings of all CCAs would be unduly burdensome, particularly when the Commission can obtain valuable information through the reporting requirements proposed by Energy Division Staff. These requirements would require reporting of information regarding contracting, financials, and plans for correction and/or market exit upon a CCA meeting the following triggers:

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[50] SDG&E Opening Brief at 22.

- Downgrade below investment grade credit rating, or
- Days Liquidity on Hand (DLOH) is less than 45 days and Debt Service Coverage Ratio falls below 1.0, or
- Cash reserves is below five percent of annual expenses, or
- Default on procurement contract required to meet Resource Adequacy requirements or to the CAISO scheduling coordinator due to non-payment, or
- Insolvency or bankruptcy.

These triggers are objective, as SDG&E desires, and would enable a more regularly updated evaluation of financial conditions than the rating agencies could provide through updating credit ratings.

4. Reject SDG&E's Proposal to Institute a Financial Review Group (FRG)

SDG&E proposes the Commission develop a FRG comprised of CCA representatives, relevant Commission staff, and consumer interest representatives to engage with CCAs without an investment grade credit rating or "reasonably appear to be experiencing financial trouble."[51] The Commission should reject this recommendation, as it extends beyond the Commission's authority and serves no clear purpose.

CCA local governing boards have oversight and approval authority over CCA procurement activities and financial decisions. Therefore, unlike with the IOUs and the Procurement Review Group (PRG), the CCA will not be filing either a quarterly compliance report or an advice letter for which those reviewing parties may participate. Indeed, this is the purpose of the PRG as the group has no authority to require changes of the IOUs nor to reject any recommended procurement strategies. It is not even the Commission that would review any changes contemplated by the CCA. Rather this would be done by the CCA Board. Given that

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51 SDG&E Opening Brief at 22.

the Commission has no authority to dictate CCA procurement and financial decisions, SDG&E's intended purpose of an FRG is unclear.

SDG&E's Opening Brief fails to provide any details on the expected outcomes of these meetings beyond warning the Commission and the POLR of a potential return of customers. Since CCAs would not have filings with the Commission that would necessitate such review by parties that would intervene in a proceeding, it is not clear what purpose SDG&E's proposal would serve. SDG&E's proposal, therefore, appears to provide no additional value relative to more substantive proposals such as financial reporting upon certain triggers, as proposed by Energy Division Staff. SDG&E also fails to provide any details on how the Commission would ensure the participants have the expertise necessary to participate, and how the Commission would ensure confidential information is not shared with other market participants.

The Commission should not introduce a new time-consuming task with no authority to impact outcomes or clear purpose. To do so would result in unreasonable spending of customer funds. The purpose of financial monitoring should be to ensure that the Commission and the POLR are not surprised by immediate customer returns. The Commission should therefore forego the establishment of an FRG and instead adopt the process in the Energy Division Staff Proposal, with the modifications described in CalCCA's Opening Brief,[52] which would require meetings between Energy Division and the CCA triggering financial reporting on up to a monthly basis.

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[52] CalCCA Opening Brief at 43-47.

V. DURATION OF POLR SERVICE

A. The Commission Should Reject SBUA's Recommendation that Returning Customers Remain on POLR Service as Long as It Takes for the POLR Rate to Merge into the Default Service or for a New CCA to Assume Responsibility for the Load

SBUA recommends POLR service be provided "as long as it takes for the POLR rate to be merged into the default service, or for a new CCA to assume responsibility for the load."[53] The Commission should not adopt this recommendation. As SCE notes, "[m]ost parties appear to agree that the switching rules remain reasonable and do not require modification."[54] This includes, apart from SBUA, a general agreement on the existing six-month duration of POLR service.

The current six-month duration of POLR service recognizes that the IOU must adjust its procurement activity to accommodate the additional load associated with the returning customers. It also sets a defined period of time that incentivizes the POLR to complete procurement and hedging activity on a timeline that supports timely return of customers to bundled service. Modifying the duration of POLR service to be for an undefined length of time (as long as it takes for the POLR rate to merge into default service) is unnecessary and diminishes these incentives.

VI. CONCLUSION

For all the foregoing reasons, CalCCA respectfully requests the Commission adopt the recommendations herein.

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[53] SBUA Opening Brief at 3.

[54] SCE Opening Brief at 7

Respectfully submitted,

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CALIFORNIA COMMUNITY CHOICE
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