FEBRUARY FILINGS

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S INFORMAL COMMENTS ON PG&E'S MEET AND CONFER DIABLO CANYON POWER PLANT

I. INTRODUCTION

California Community Choice Association[1] (CalCCA) appreciates the opportunity to submit the following informal comments to Pacific Gas and Electric Company (PG&E) on the February 6, 2023, Meet and Confer (M&C), intended to provide an overview of the accounting structure for tracking costs related to the continued operation of Diablo Canyon Power Plant (DCPP), specifically the Diablo Canyon Transition and Relicensing Memorandum Account (DCTRMA) and the Diablo Canyon Extended Operations Balancing Account (DCEOBA).

II. GENERAL COMMENTS

While PG&E's draft Preliminary Statements for the DCTRMA and DCEOBA acknowledge, in some instances, that future California Public Utilities Commission (Commission) action may impact the mechanics of each account, PG&E should expressly clarify in its Tier 3 advice letter that the draft Preliminary Statements for the DCTRMA and DCEOBA are subject to change through Commission action in the Order Instituting Rulemaking 23-01-007 (OIR). For example, it is CalCCA's understanding, based on PG&E's comments during the M&C that the allocation among load serving entities (LSEs) for net costs recorded to the DCEOBA Extended

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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 Choice 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.

Operations subaccount will be addressed in the OIR. Commission action in the OIR, therefore, will likely directly impact the DCEOBA, and PG&E's Tier 3 advice letter should clarify that possibility. Another example is in the DCEOBA Preliminary Statement where PG&E mentions, "Disposition of the balance in the account will be through the Annual Electric True-up advice letter process as authorized by the Commission." Again, this process will be defined during the OIR and thus may require changes to the Preliminary Statements at a later date.

III. COMMENTS ON THE DIABLO CANYON TRANSITION AND RELICENSING MEMORANDUM ACCOUNT

During the M&C, PG&E explained that the DCTRMA will track "incremental costs" incurred to preserve the option for extended operations at DCPP. This is consistent with PG&E's DCTRMA preliminary statement, which states that expenses recorded to the DCTRMA "include incremental costs" related to several listed activities.[2]

PG&E's DCTRMA preliminary statement does not define the term "incremental costs," nor did PG&E do so during the M&C. This creates some uncertainty with respect to PG&E's accounting process and the costs that it will record to the DCTRMA. In light of the Commission's directives in Decision (D.) 22-12-005,[3] which underline the need for clarity regarding PG&E's accounting associated with both the DCTRMA and DCEOBA, PG&E should elaborate in its Tier 3 advice letter filing,[4] in as much detail as possible, (1) how it defines

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2 Electric Preliminary Statement Diablo Canyon Transition and Relicensing Memorandum Account (DCTRMA), para 1.

3 *See, e.g.* D.22-12-005 at 18 (stating that "PG&E should, at a minimum, be able to explain why the associated activity for each cost was necessary and consistent with statute; whether the costs incurred are incremental and reasonable; and whether any of the costs might otherwise be eligible to be recovered through government funding and were initially being tracked as part of the DCTRMA.")

4 PG&E's Tier 3 advice letter is due by March 6, 2023.

"incremental costs," and (2) how PG&E intends to identify and track those costs. PG&E provided a brief description of these costs in its opening comments to Application (A.) 16-08-006, largely based on language from Senate Bill (SB) 846; however, PG&E should expand on those comments to describe the internal procedures that it will follow to segregate eligible costs.

IV. COMMENTS ON THE DIABLO CANYON EXTENDED OPERATIONS BALANCING ACCOUNT

During the M&C, PG&E noted in its presentation that the California Independent System Operator Corporation (CAISO) market revenue would be applied to all three subaccounts in the DCEOBA, including the Extended Operations Subaccount, Liquidated Damages Subaccount, and Volumetric Performance Fee Subaccount. Pursuant to SB 846, the CAISO market revenue may be allocated to customers of all jurisdictional LSEs (as an offset to extended operations costs) or customers of jurisdictional LSEs only in PG&E service territory (if there is excess market revenue at the end of a year). According to PG&E's draft preliminary statement for the DCEOBA, allocation among customer groups would be a function of the subaccount to which the market revenue is recorded. PG&E's draft Preliminary Statement states, "During the period of extended operations, revenues from the sale of electricity into the CAISO market will be used to offset costs recorded in the Extended Operations Subaccount. Any excess revenues remaining after offsetting costs will be credited to the Volumetric Performance Fee Subaccount." It is not clear that PG&E's presentation during the M&C, SB 846, and PG&E's draft Preliminary Statements can be reconciled. Additional clarity is needed to ensure the CAISO market revenue is credited to the appropriate customer groups.

First, to the extent the CAISO market revenue can be recorded to multiple DCEOBA subaccounts, the Preliminary Statement should list the subaccounts to which the CAISO market revenue may be applied and the order, or sequence, used to determine whether there is excess market revenue. Furthermore, for the Extended Operations Subaccount, PG&E should also identify the specific cost line items eligible to be offset by the CAISO market revenue. At this stage, the details of cost and benefit allocations are not fully determined so PG&E should make entries into the balancing accounts such that it can adjust those entries based on the attribution of costs and benefits decided in the proceeding at a later time.

Second, in the draft Preliminary Statement, the Liquidated Damages subaccount does not include a credit for CAISO market revenues. The draft Preliminary Statement appears to be consistent with SB 846, but it is not consistent with the discussion at the M&C. PG&E should resolve the discrepancy between the presentation and the Preliminary Statement. If PG&E proposes that the CAISO market revenue will be credited to the Liquidated Damages revenue subaccount it should explain how such proposal is consistent with SB 846.

V. CONCLUSION

CalCCA appreciates the opportunity to share these informal comments and urges PG&E to consider the recommendations herein.

Date: February 10, 2023

/s/ Eric Little

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STATE OF CALIFORNIA ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION

IN THE MATTER OF: *Reliability Reserve Incentive Programs [22-RENEW-01]*	Docket No. 22-RENEW-01 RE: Demand Side Grid Support Program and Distributed Electricity Backup Assets Program

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE JANUARY 27, 2023 WORKSHOP ON THE DEMAND SIDE GRID SUPPORT PROGRAM AND DISTRIBUTED ELECTRICITY BACKUP ASSETS PROGRAM

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February 17, 2023

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STATE OF CALIFORNIA ENERGY RESOURCES
CONSERVATION AND DEVELOPMENT COMMISSION

IN THE MATTER OF: *Reliability Reserve Incentive Programs [22-RENEW-01]*	Docket No. 22-RENEW-01 RE: Demand Side Grid Support Program and Distributed Electricity Backup Assets Program

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE JANUARY 27, 2023 WORKSHOP ON THE DEMAND SIDE GRID SUPPORT PROGRAM AND DISTRIBUTED ELECTRICITY BACKUP ASSETS PROGRAM

The California Community Choice Association[1] (CalCCA) appreciates the opportunity to provide comments on the *January 27, 2023 Workshop on the Demand Side Grid Support Program and Distributed Electricity Backup Assets Program* (WS).

I. INTRODUCTION

As part of the Strategic Reliability Reserve created through Assembly Bill (AB) 205 (as amended by AB 209), the Demand Side Grid Support (DSGS) and Distributed Electricity Backup Assets (DEBA) programs are intended to incentivize the availability of load reduction and emergency supply during "extreme events."[2] DSGS complements existing demand response (DR) programs, such as the investor-owned utilities' (IOUs') Emergency Load Reduction

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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 Choice 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] Public Resources Code (PRC) § 25792(a) (creating DSGS), §§ 25791-25791.5 (creating DEBA) (both created through AB 205, as amended by AB 209). An "extreme event" is defined in the PRC as either: "(1) [a]n event occurring at a time and place in which weather, climate, or environmental conditions, including temperature, precipitation, drought, fire, or flooding, present a level of risk that would constitute or exceed a one-in-ten event, as referred to by the North American Electric Reliability Corporation, including when forecast in advance by a load-serving entity or local publicly owned electric utility[,] (2) [a]n event where emergency measures are taken by a California balancing authority, including when forecast in advance by the California balancing authority."

Program (ELRP) under the jurisdiction of the California Public Utilities Commission (CPUC).[3] While some community choice aggregator (CCA) customers may get enrolled in ELRP through the IOUs which provide transmission and distribution services to CCA customers, CCAs cannot receive funding to themselves cannot enroll customers in ELRP and administer that program. As a result, significant untapped incremental load and potential emergency supply exists with CCA customers.

AB 209 amended AB 205 to ensure all California energy customers can enroll in DSGS, as long as the customer is not already enrolled in a CPUC jurisdictional DR program.[4] The California Energy Commission (CEC), however, has not yet added CCAs as eligible providers under the DSGS Guidelines, despite recognizing in a DSGS Guideline Advisory that a result of AB 209 was to incorporate CCAs into DSGS.

CCAs serve a substantial portion of California retail load – the Commission reports in its 2022 Update to the California Energy Demand forecast that CCAs will serve 26 percent of the state-wide load in 2023 (CCAs serve 63 terrawatt hours (TWh) of the total 239 TWh California load).[5] CCAs are well connected to their communities, and well suited to locate and enroll CCA customers in DR programs to provide incremental load reduction and emergency supply. Given the opportunity to enroll customers through DSGS, CCAs can bring to the table additional customers to ensure reliability.

As explained more fully below, CalCCA provides the following recommendations for the updated DSGS guidelines to expand and improve the program:

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3 *See* D.21-03-056, *Decision Directing Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company to take Actions to Prepare for Potential Extreme Weather in the Summers of 2021 and 2022,* R.20-11-003 (Mar. 25, 2021) (creating the ELRP); *see also* D.21-06-027, *Order Modifying Decision 21-03-056 to Clarify Guidance in the Emergency Load Reduction Program Regarding a Day-of Trigger,* R.20-11-003 (June 24, 2021) (modifying the ELRP); *see also* D.21-12-015, *Phase 2 Decision Directing Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company to Take Actions to Prepare for Potential Extreme Weather in the Summers of 2022 and 2023,* R.20-11-003 (Dec. 2, 2021) (modifying the ELRP).

4 *CEC Guideline Advisory; Demand Side Grid Support Program Provisions During the State of Emergency* (DSGS Guideline Advisory), Docket No. 22-RENEW-01 (Sept. 3, 2022) at 2: located at https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=22-RENEW-01.

5 22-IEPR-03, *CEC California Energy Demand Update,* Form 1.1c, located at https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2022-integrated-energy-policy-report-update-2.

- Modify the DSGS program guidelines to include CCAs as eligible DSGS providers as allowed by AB 209, and recognized by the Commission in its DSGS Guideline Advisory; and

- Modify the DSGS program guidelines to ensure effective operations as additional DSGS providers are added, including: (1) establishing systems to allow LSEs to prevent dual enrollment in DR programs; (2) ensuring visibility into load reduction for the California Independent System Operator (CAISO), IOUs, and other LSEs (including CCAs); and (3) compensating behind the meter resources for exporting during emergency events.

In addition, as the Commission develops guidelines for the DEBA program, CalCCA recommends that the Commission consider incorporating incentives for behind-the-meter resources.

II. COMMUNITY CHOICE AGGREGATORS SHOULD BE ADDED AS ELIGIBLE DSGS PROVIDERS

The Commission should modify the DSGS guidelines to add CCAs as eligible DSGS providers. As recognized by the Commission in its DSGS Guideline Advisory, AB 209 opened the DSGS program to CCAs:

If AB 209 (Ting, Statutes of 2022) is enacted into law [which it was days after the DSGS Guideline Advisory was issued], the DSGS Program <u>will immediately be opened to [CCAs]</u> and specific customers in [IOU] territories, except those that are enrolled in [DR or ELRP] offered by entities under the jurisdiction of the [CPUC].[6]

As set forth more fully below, CCAs are uniquely suited to locate and enroll customers in its service territory to provide incremental load reduction and emergency supply over and above what IOUs can provide by their enrollment of customers in ELRP. Given that CCAs cannot themselves enroll customers in and administer the ELRP program, and that CCA programs in existence and in development demonstrate the unique ability of CCAs to connect with and enroll customers in DR programs, adding CCAs as DSGS providers will provide incremental reliability benefits not otherwise available.

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[6] DSGS Guideline Advisory at 2 (emphasis added).

A. AB 209 Clarifies That Eligible DSGS Recipients Include CCA Customers Not Enrolled in CPUC Jurisdictional Demand Response or Emergency Load Reduction Programs

AB 209, signed by the Governor on September 6, 2022, amended Public Resources Code section 25792(b) (enacted by AB 205) to ensure that eligible DSGS recipients include all energy customers (including CCA customers), except those enrolled in CPUC jurisdictional DR or ELRP programs.[7] AB 209 therefore remedied an ambiguity in AB 205 allowing all energy customers to be DSGS eligible except those eligible for CPUC-jurisdictional DR or ELRP programs.[8] CalCCA noted in its Comments on the first draft of the DSGS guidelines the nonsensical exclusion by AB 205 of customers from DSGS who were simply eligible for DR or ELRP programs.[9] Instead, CalCCA pointed out that the more logical statutory intent of the eligibility criteria is to limit actual dual enrollment in DR or ELRP programs.[10]

AB 209 in fact modified section 25792(b) to remove AB 205's prohibition of participation in DSGS by customers who were simply eligible for other DR or ELRP programs. As noted above, the CEC recognized the impact of AB 209 in its DSGS Guideline Advisory in which it recognized that the passage of AB 209 will immediately open DSGS to CCAs. By revising the Guidelines to include CCAs as DSGS providers, the Commission can follow through on its Advisory to incorporate CCAs into the program.

B. Allowing CCAs to be DSGS Providers Will Allow Them to Recover Costs for Programs Providing Incremental Load Reduction and Emergency Supply During Extreme Events

Adding CCAs as DSGS providers will allow them to recover costs for programs capitalizing on the CCAs' ability to bring additional customers under the umbrella of DR to provide incremental load reduction and emergency supply during extreme events. While the IOUs may enroll some CCA customers in ELRP, CCAs themselves are not themselves able to enroll customers in or administer (and therefore recover costs through) the ELRP. Providing CCAs with cost recovery through DSGS for programs for load shifting and reduction during

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7 Public Utilities Code § 25792(b) (as amended by AB 209).

8 *California Community Choice Association's Comments on the Proposed Draft Program Guidelines – Demand Side Grid Support (DSGS) Program, First Edition,* Docket No. 22-RENEW-01 (July 29, 2022), at 2.

9 *Id.* at 3.

10 *Id.*

extreme events will capitalize on the unique ability of CCAs to locate potential incremental reductions and emergency supply within their communities.

1. CCAs as DSGS Providers Can Supplement Customers Enrolled in ELRP

ELRP compensates customers for load reductions during extreme events. However, enrollment of customers in and administration of the ELRP can only be conducted by the IOUs, who are provided the authority and funding to conduct the ELRP program. The IOUs enroll customers either through auto-enrollment (for certain customers such as those in the CARE program), or through IOU marketing and enrollment of customers (such as through the IOUs' websites). Customers enrolled in ELRP may include CCA customers enrolled by an IOU as a CCA customer's provider of transmission and distribution services.[11] However, CCAs have widely found that many of their customers are either unaware that they are enrolled in ELRP, or simply haven't enrolled and cannot participate in load reduction or shifting. Given the opportunity and funding to create more effective programs to incentivize customers to reduce or shift their load during emergencies, CCAs can provide incremental reliability benefits during extreme events.

2. CCA Demand Response Programs Demonstrate the Untapped Potential for Emergency Reliability Benefits

CCAs, created by their local communities, are uniquely positioned to connect with, market to, and enroll their customers in DR programs. Given the funding to locate customers in their territories not already enrolled in CPUC jurisdictional DR programs, CCAs can bring additional customers who can provide incremental load reduction and supply in extreme events.

Several CCA programs demonstrate the ability of CCAs to design simple and effective programs to shift load and provide emergency supply. First, Marin Clean Energy's (MCE's) existing Peak FLEXmarket program (PeakFLEX) shifts customer energy usage away from peak hours in the summer and during extreme events. The PeakFLEX program not only compensates residential and commercial customer energy load shedding or shifting during extreme events (at $2.00 per kilowatt-hour), but also provides payments for daily energy load shedding or shifting during peak hours (4-9 p.m. from June 1 through October 31). The PeakFLEX program is

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[11] A CCA can annually opt-out all of its residential customers from ELRP. *See* D.21-12-015 at 57. Such an opt-out may be done, for example, if a CCA has its own DR program providing alternative benefits to ELRP.

particularly innovative as it is based on a technology agnostic, market- and performance-based approach. Any type of resource or intervention strategy (e.g., energy storage, electric vehicles, or behavioral DR) can enroll under the program as long as it can achieve measurable savings at the meter during peak hours. MCE, whose customers are able to also enroll in ELRP, was able to originally enroll 700 customer accounts, and added 2000 residential and 53 non-residential additional customers during the September 2022 heat wave. The PeakFLEX program has been funded in 2022 and 2023 through the CPUC's energy efficiency proceeding, but may need additional funding when the funding terminates at the end of 2023.

Through the Resilient Home program, East Bay Community Energy (EBCE) partners with solar company SunRun, Inc. (SunRun) to assist residential customers with installing behind-the-meter solar and battery systems, as well as providing financing options. In exchange for a flat incentive, Resilient Home customers allow EBCE to coordinate the dispatch of their batteries. These batteries are optimized to charge midday during times of high solar generation, and to dispatch during weekday evening hours. With over 1,100 residential solar and storage systems under management, EBCE delivers real, ongoing peak load management on a daily basis, including during CAISO peak days. If Resilient Home customers are eligible for DSGS incentives, EBCE can adjust system dispatch behavior to prioritize incremental load shifting during grid emergency events. Increased price signals for dispatch during stress events can also incentivize an increased uptake of managed systems, as EBCE can use this funding stream to advance efforts to expand beyond the current program. As a DSGS provider, EBCE will seek to enroll existing solar and storage systems operating "in the wild," or in an unmanaged state, retrofitting existing standalone solar systems with batteries, and increasing the sale of new systems to procure incremental demand response capabilities.

Another approach to enrolling customers to provide incremental load shifting is through a program being developed by Clean Power Alliance of Southern California (CPA) to incentivize the building of new solar and storage projects that could potentially dispatch during extreme events. CPA's Power Ready program is a community benefit offered to CPA's member agencies to make public buildings that serve critical community purposes energy-resilient by installing solar and storage systems to provide backup energy during an outage. CPA is seeking competitive proposals from developers/financiers to build, own, and operate the systems for 20 years. The project portfolio for all sites is expected to be approximately 1.7 megawatts (MW) of solar and 3.6 MW of energy storage. CPA could potentially enroll these projects as dispatchable resources under the DSGS program if behind the meter resources are able to export under the DSGS program, as recommended below.

Given the funding and opportunity to design programs and enroll CCA customers in DR programs under DSGS, CCAs can capitalize on their unique community connections to locate untapped incremental load reduction and emergency supply opportunities. As a result, the Commission should revise the Guidelines to immediately include CCAs as eligible DSGS providers.

III. THE DSGS GUIDELINES SHOULD BE MODIFIED TO INCREASE THE EFFECTIVENESS OF THE DSGS PROGRAM

CalCCA appreciates the approach of the Commission to incorporate revisions based on "lessons learned" from the first summer implementing the DSGS program. As additional categories of DSGS providers (such as CCAs) are added, the Commission should also consider the following recommendations to increase the effectiveness of the program.

First, systems must be established to prevent dual participation in load-modifying demand response programs. Dual participation (and compensation) is prohibited by Public Utilities Code section 25792. Therefore, adequate systems must be in place to check both eligibility and enrollment of customers in the available DR programs. Currently, CAISO market integrated DR programs are included with the Demand Response Registration System (DRRS) and enrollment of customers can be checked within that system. However, such a system does not exist for load modifying DR programs. As proposed by Sunrun and Leap in their January 26, 2023 DSGS recommendations, to prevent "double counting" of participants, a verification of enrollment could be established through an eligibility check between LSEs.[12] Such a check could be maintained, as Sunrun suggests, through a live spreadsheet and cooperation between LSEs.[13]

Second, the Commission must ensure visibility into DR programs not only to CAISO and the IOUs, but also to LSEs. Without such visibility especially into which customers are enrolled in other DR programs, LSEs cannot effectively determine which customers can be enrolled in alternative programs.

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[12] Dockets 22-RENEW-01 and 21-ESR-01, *Sunrun, Inc. and LEAP Distributed Energy Resource Program Recommendations* (Jan. 26, 2023), at 3-4.

[13] *Id.*

Third, exports of behind the meter resources during emergency events should be eligible for DSGS compensation. While compensation for such exports may be limited during normal circumstances, CalCCA's understanding is that during extreme events behind the meter exports have been compensated through other DR programs.

IV. THE DEBA PROGRAM SHOULD INCORPORATE INCENTIVES FOR BEHIND THE METER RESOURCES

As the Commission develops the DEBA program, CalCCA encourages the incorporation of incentives for behind the meter resources. Such incentives can be coupled with direct funding for front of the meter resources to serve as on-call emergency supply or load reduction during extreme events.

V. CONCLUSION

CalCCA looks forward to further collaboration on these topics.

Respectfully submitted,

Evelyn Kahl

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

February 17, 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 COMMENTS ON ASSIGNED COMMISSIONER'S AMENDED SCOPING MEMO AND RULING

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February 24, 2023

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SUMMARY OF RECOMMENDATIONS

- The California Public Utilities Commission (Commission) must acknowledge the severely constrained Resource Adequacy (RA) market conditions in a Finding of Fact in its Implementation Track Phase 3 Decision;
- Sources of RA market scarcity are masked in the bi-lateral market, necessitating additional data transparency;
- The supply and demand imbalance requires consideration of load-serving entity (LSE) efforts to procure before penalizing;
- The Commission should implement a system and flexible RA waiver process;
- If the Commission declines to adopt a system and flexible RA waiver for the year-ahead and month-ahead showings, the Commission should implement a waiver process for year-ahead showings at minimum;
- The Commission should not apply points to LSEs with RA deficiencies who took reasonable efforts to comply;
- The Commission should not publish LSE penalty information that exposes market sensitive information;
- The Commission should clarify Energy Division's penalty proposal to state that LSEs will pay the penalty price of the tier the LSE is in at the point in time that the non-compliance event occurs;
- Energy Division staff's proposal to prohibit LSE expansion for RA non-compliance oversteps the Commission's legal authority;
- Energy Division's LSE expansion proposal is arbitrary and adds no incremental reliability value;
- Energy Division's RA import proposals will diminish the availability of RA imports in an already constrained market;
- The Commission should restructure the effective Planning Reserve Margin (PRM) so that it is truly incremental to RA resources;
- The Commission should align resource modeling and counting with resource capabilities;
- The Commission should prioritize resource development and consider multi-year RA proposals in concert with the procurement program in development in the Integrated Resource Plan (IRP) proceeding;

SUMMARY OF RECOMMENDATIONS continued

- The Commission should not lock in year-ahead load forecasts for setting RA requirements; doing so would result in inaccurate requirement allocation; and
- The Commission should allocate all Cost Allocation Mechanism (CAM) resources by Maximum Cumulative Capacity (MCC) bucket, rather than across all buckets evenly and update the MCC data set.

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 COMMENTS ON ASSIGNED COMMISSIONER'S AMENDED SCOPING MEMO AND RULING

California Community Choice Association[1] (CalCCA) submits these Comments in response to the *Assigned Commissioner's Amended Scoping Memo and Ruling,*[2] dated September 2, 2022, on the workshop and all proposals filed, and *E-mail Ruling Granting Western Power Trading Forum's Request for Extension to File Comments on Phase 3 Proposals*, dated February 13, 2023.

I. INTRODUCTION

The resource adequacy (RA) supply available within the California Independent System Operator (CAISO) balancing authority area (BAA) for 2023 appears inadequate to meet the RA program compliance requirements. The Commission has failed to acknowledge this shortfall to date, as reflected by the proposals advanced by Energy Division in response to the Ruling. Until the Commission acknowledges that insufficient RA capacity exists and designs policy responses

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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 Choice 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 *Assigned Commissioner's Amended Scoping Memo and Ruling*, Rulemaking (R.) 21-10-002 (Sept. 2, 2022) (Ruling): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M496/K684/496684932.PDF.

in that light, the RA program will continue to be dysfunctional – with load serving entities (LSEs) unable to collectively comply despite their best efforts to procure RA even under exorbitant prices.

In these comments, CalCCA presents an updated stack analysis (section II) that compares available RA supply with the RA requirements. The stack analysis shows that the margin is razor thin "on paper" due to a confluence of factors including: (1) increased extreme weather conditions, (2) uncertainty in hydro availability, (3) increased planning reserve margins (PRMs) and decreased effective load carrying capabilities (ELCCs), (4) unnecessarily restrictive RA import requirements, and (5) effective PRM procurement that cannibalized the existing RA procurement stack. LSEs procuring in the market have likely experienced margins even thinner than what can be shown on paper due to factors that cannot be captured in the stack analysis without additional data. For example, the entire Western region is capacity constrained and resources once available to California LSEs may have gone to entities outside the CAISO BAA who also must ensure capacity sufficiency.

Under these conditions, RA program compliance has become a game of musical chairs. Some chairs are occupied by the investor-owned utilities (IOUs) before the game even starts, as they hold most "legacy" supplies built prior to the recent growth of community choice aggregation (CCA) and the expansion of direct access (DA). Other chairs have been grabbed by out-of-state entities experiencing similar capacity constraints and setting up their own efforts to ensure resource adequacy. This leaves some California LSEs without a chair when the music stops. Until more new resources come online, the race to find a chair in the game will have detrimental consequences for all consumers. The RA shortfall has driven up prices paid by consumers. Resources that garnered $3.63 kilowatt (kW)-month in 2019[3] rose to prices many multiples of that level for summer 2023 and are increasingly unavailable at any price.[4] Sellers are the only market participants who benefit from this pressure.

The Energy Division makes proposals that are blind to the market conditions that make compliance difficult, if not impossible. In limiting CCA expansion, Energy Division's proposal extends beyond the Commission's jurisdictional authority without any incremental benefit to reliability, making CCA expansion contingent upon potentially unmeetable compliance obligations. Energy Division's proposal also doubles down on penalties, which do nothing to get new resources in the ground; they instead unnecessarily add to customer costs and indirectly increase the cost of supply. Additionally, extending the use of the "effective" PRM would further cannibalize the RA supply stack without modifications to make sure the "effective" PRM procurement is truly incremental. With current RA market dynamics in mind, CalCCA offers the following recommendations:

- The Commission must acknowledge the severely constrained RA market conditions in a Finding of Fact in its Implementation Track Phase 3 Decision;
- Sources of RA market scarcity are masked in the bi-lateral market, necessitating additional data transparency;
- The supply and demand imbalance requires consideration of LSE efforts to procure before penalizing;
- The Commission should implement a system and flexible RA waiver process;
- If the Commission declines to adopt a system and flexible RA waiver for the year-ahead and month ahead showings, the Commission should implement a waiver process for year-ahead showings at minimum;

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[3] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2019rareport-1.pdf, at 22.

[4] The Commission collects information about RA prices and should have the actual prices paid which are ultimately used in benchmarks for RA by the Commission.

- The Commission should not apply points to LSEs with RA deficiencies who took reasonable efforts to comply;
- The Commission should not publish LSE penalty information that exposes market sensitive information;
- The Commission should clarify Energy Division's penalty proposal to state that LSEs will pay the penalty price of the tier the LSE is in at the point in time that the non-compliance event occurs;
- Energy Division staff's proposal to prohibit LSE expansion for RA non-compliance oversteps the commission's legal authority;
- Energy Division's LSE expansion proposal is arbitrary and adds no incremental reliability value;
- Energy Division's RA import proposals will diminish the availability of RA imports in an already constrained market;
- The Commission should restructure the effective PRM so that it is truly incremental to resource adequacy resources;
- The Commission should align resource modeling and counting with resource capabilities;
- The Commission should prioritize resource development and consider multi-year RA proposals in concert with the procurement program in development in the Integrated Resource Planning (IRP) proceeding;
- The Commission should not lock in year-ahead load forecasts for setting RA requirements; doing so would result in inaccurate requirement allocation; and
- The Commission should allocate all cost allocation mechanism (CAM) resources by maximum cumulative capacity (MCC) bucket, rather than across all buckets evenly and update the MCC data set.

These recommendations aim to stabilize the RA market and enhance the availability of already operational RA until the supply stack increases to sufficient levels through resource development taking place via the IRP process and procurement mandates.

II. THE COMMISSION MUST ACKNOWLEDGE THE SEVERELY CONSTRAINED RA MARKET CONDITIONS IN A FINDING OF FACT IN ITS IMPLEMENTATION TRACK PHASE 3 DECISION

A wide range of factors have contributed to the current circumstances in which there is insufficient RA supply to meet the RA program compliance requirements. These factors include:

- Weather conditions are more extreme, increasing load and reducing generation output;
- Hydro resource availability has declined under drought conditions;
- New resources are delayed due to permitting, interconnection, and supply chain challenges;
- Reduction in ELCC values reduced reliance on wind and solar resources to meet RA requirements;
- Increases in PRMs to 16 percent, with a 20-22.5 percent "effective" PRM for IOUs, increased RA requirements;
- The Commission's definition of "incremental" procurement to meet the effective PRM encouraged IOUs to cannibalize the existing RA resource stack, reducing supply for other LSEs; and
- Unnecessarily restrictive requirements for energy imports under the Commission's RA program reduced the availability of imports to the Commission-jurisdictional RA market.

The result of these contributing factors is shown in Figure 1 below, in which demand for RA exceeds the available supply in three of the four peak summer months.[5] This is the case even after accounting for imports and the expected addition of resources between now and the month-ahead RA filings. The projected deficit is as high as nearly 1,900 megawatts (MW) in September 2023.

[5] A detailed list of sources and an explanation of each row of the stack is included in Appendix A.

Figure 1

		Jun	Jul	Aug	Sep
1	Owned by Calpine	5,874	5,864	5,861	5,867
2	Owned by AES	3,657	3,657	3,655	3,655
3	Owned by NRG	2,321	2,317	2,315	2,322
4	Owned by Other	35,956	36,402	35,690	34,973
5	Thermal Plant Derate	(726)	(726)	(726)	(726)
6	Imports	5,500	5,500	5,500	5,500
7	Event-Based Demand Response	995	1,045	1,077	1,090
8	**Total RA Supply**	**53,577**	**54,059**	**53,372**	**52,681**
9	CAISO 1-in-2 Load	42,056	45,397	45,922	46,819
10	Reserve Margin (16%)	6,729	7,264	7,347	7,491
11	Excess IOU Resources Above PRM (D.21-12-015)	794	925	664	206
12	Supply-Side Emergency Reliability Procure. (D.21-12-015)	883	933	824	1,125
13	Retention for Substitution	619	619	619	619
14	**Total RA Demand**	**51,082**	**55,138**	**55,376**	**56,260**
15	Surplus Supply (Deficit)	2,496	(1,079)	(2,004)	(3,579)
16	Expected New Resources	-	-	1,695	1,695
17	Surplus Supply (Deficit) with New	2,496	(1,079)	(309)	(1,884)

LSEs procuring RA for 2023 likely experienced even greater levels of market tightness than this analysis suggests because of one additional factor that cannot be quantified with the public information available. That is:

- The entire Western region is constrained, reducing the availability of imports to California and risking increased exports of California resources to meet other Western region requirements (e.g., Western Resource Adequacy Program (WRAP)).

As the Western Electricity Coordinating Council's (WECC's) August 2020 Heatwave Event Analysis Report finds, increased demand during summer months across the Western Interconnection has created more competition for available generation. The Report also finds that seasonal demand differences between BAAs that once allowed excess generation in the north to supply demand in the south in the summer (and vice versa) appear to be diminishing, as BAAs that previously peaked in the winter months now peak in summer or in both summer and winter.[6] This increases demand for available generation in the summer when California's RA needs are

[6] Western Electricity Coordinating Council, *August 2020 Heatwave Event Analysis Report*, March 19, 2021, at 2-3.

highest. Other BAAs have recognized the need to ensure sufficient capacity is available to serve their load through forward commitments and have begun implementing their own RA programs. The WRAP had its first non-binding RA showing in October 2022 for 2023, and BAAs may be contracting with capacity that could have been available to meet California RA obligations to meet their WRAP RA obligations.[7]

West wide capacity constraints risk the levels of both imports of RA capacity declining and exports of RA capacity increasing. CalCCA's stack analysis assumes 5,500 MW of imports, meaning roughly 10 percent of the RA requirement would be met by imports. It is unclear whether California will be able to rely on that level of RA imports as other western regions are also facing capacity constraints and uncertainty around how much capacity will be available following years of drought. The stack analysis also assumes the total RA supply included in the stack is entirely sold within the CAISO BAA. While CalCCA had to make that assumption given the lack of public information about where RA capacity was sold, it is unlikely that *none* of the RA capacity on the net qualifying capacity (NQC) list was sold outside the CAISO.

The Commission must acknowledge in a Finding of Fact in its Decision that the stack of RA supply is insufficient to meet demand, and that this shortfall makes it difficult, if not impossible, for LSEs to comply with their obligations. The Commission must also consider this shortfall when evaluating the proposals put forth in this proceeding and making policy decisions, as decisions that increase LSEs' exposure to penalties do nothing to increase supply in the short-term and serve only to increase customers costs.

[7] The desire by other BAAs to have sufficient capacity could reduce the available resources to California by either limiting the resources available to California to import and by entities outside of California procuring capacity from California resources for export.

III. SOURCES OF RA MARKET SCARCITY ARE MASKED IN THE BI-LATERAL MARKET, NECESSITATING ADDITIONAL DATA TRANSPARENCY

California wisely determined post 2000 energy crisis that a market to ensure sufficient capacity was available to meet energy needs of the grid. That market did not follow the same structure as the energy and ancillary services markets employed by the CAISO. Instead, the RA market is a bilateral market. As such, transparency into this market is far less than within other markets in California. In addition, the bilateral RA market does not have a market monitor like the energy and ancillary services markets in the CAISO. This makes evaluation of sufficient capacity to meet the RA need a difficult task. CalCCA offers in these comments a stack analysis demonstrating that there may not be sufficient resources as well as a discussion of increased competition for those resources driving scarcity and significant potential for LSEs to find it impossible to meet their obligations. Without additional transparency, understanding the causes of RA deficiencies will be unlikely and evaluating fixes to the problem haphazard. California's grid reliability and customer affordability are too much to risk in not evaluating the issues of an apparent lack of capacity without a detailed look at the real availability of in-state and import resources to meet RA needs.

The need to evaluate the efficacy of the fleet of resources in meeting California's needs is even more critical since the Commission lacks jurisdiction over sellers to ensure that market power is not exercised either through physical or financial withholding. While the RA market is not a central market, even the bilateral market is a wholesale market whose transactions are governed by the Federal Energy Regulatory Commission (FERC). The CAISO energy and ancillary services markets contain market power mitigation measures that are enforced through the CAISO tariff which is FERC jurisdictional. Short of filing a complaint with the FERC, entities are simply left to wonder if the current conditions are driven by market participant actions or by scarcity of the product within California and WECC.

The Commission must take all actions possible now to make transparent to all jurisdictional entities the availability of capacity necessary to achieve RA compliance given the factors described in this section and combined with: (1) proposals to increase the PRM (increasing the demand for capacity and placing even more pressure on the market); (2) movement to a Slice of Day RA model where scarcity of not just months but of individual hours will complicate the market further; (3) a penalty mechanism that can cause LSEs to face costs of \$26.64/kW-month as well as face CAISO backstop costs; (4) a dramatic new penalty that would cease the expansion of LSEs due to RA failures without regard to whether those failures were caused by the market itself; and (5) an Energy Division proposal in the Provider of Last Resort proceeding that will make the amount of financial security posted dependent on RA compliance again without regard to whether compliance failures were caused by the market itself.

For these reasons, the Commission should work with the CAISO to determine the availability of RA resources to Commission jurisdictional LSEs including; 1) the amount of CAISO NQC that was shown in the Year-Ahead RA showing process; 2) the shown Year-Ahead NQC by resource category (i.e., renewables, gas, storage, imports, new build, etc.) compared to the 2021 and 2022 showings by category, and 3) the amount of import RA shown in the 2023 Year-Ahead RA showing process compared to the past five years of import RA shown in the Year-Ahead process. To the extent a jurisdictional LSE(s) showed partial NQC, the Commission should ask the LSE(s) to determine if the remaining NQC is under contract and will likely be shown in the monthly process or not. If the remaining NQC is not under contract to a jurisdictional LSE, this would raise the question of whether that capacity will be available to meet further RA needs. The Commission should work with the WRAP to determine how much capacity has been procured within that program, including resources from within the CAISO, to determine the impact of additional demand for capacity on the ability of the entire WECC to meet its RA needs. Finally, the Commission should work with owners of hydro resources throughout the WECC to determine their willingness to sell a Year-Ahead RA product in October of the preceding year, prior to the most significant portion of the precipitation year, given that many consider the current western drought conditions to be the worst in 1,200 years. Only after analyzing and understanding these facts can the Commission make an informed decision about the severity, cause, and solutions to the current RA shortfall.

IV. THE SUPPLY AND DEMAND IMBALANCE REQUIRES CONSIDERATION OF LSE EFFORTS TO PROCURE BEFORE PENALIZING

A. System RA Penalty Waiver History and Background

Three regulatory programs include penalties for non-compliance: (1) the RA program; (2) the Commission's IRP procurement mandates under the Mid-Term Reliability (MTR) mandate in Decision (D.) 21-06-035; and (3) the Renewable Portfolio Standard (RPS) program. The requirements of each program, and the penalties for non-compliance, create a regime with multiple levels of exposure and costs for non-compliance. The IRP and RPS programs each take into account LSEs' efforts to comply before assessing penalties, while the RA program largely does not. In IRP, enforcement of the MTR Order is progressive, and will begin with an initial warning letter and culminate in penalties subject to a vote by the full Commission. The Commission will consider good faith efforts, including the conduct of the CCA (including history of violations, and actions to prevent, detect, disclose and rectify a violation). The Commission will also consider the totality of the circumstances in furtherance of the public interest.[8] Similarly, in RPS, waivers can be granted under certain circumstances, including permitting delays, interconnection issues, and insufficient supply.[9]

In RA, on the other hand, the Commission can only waive LSE penalties in very limited circumstances. The RA program has a waiver process for local RA only, which applies only to LSEs in the San Diego area now that the central procurement entities (CPEs) are conducting local RA procurement in Pacific Gas and Electric Company (PG&E) and Southern California Edison (SCE) areas.[10] The Commission adopted the local RA penalty waiver process for LSEs who cannot meet their local RA obligations at a reasonable price in D.06-06-064 as a market power mitigation measure. [11] Often all generators within a local, transmission-constrained area are necessary to meet the local RA requirement for that area, and therefore, those generators can exert market power. LSEs who cannot meet their local RA requirements can file a request for a waiver. The Commission may grant the request for a waiver if the LSE can demonstrate that it made every commercially reasonable effort to contract for local RA resources.

Unlike for local RA, IRP, and RPS compliance obligations, the Commission does not consider LSEs' efforts to procure before assessing penalties for system and flexible RA

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8 D.21-06-035, *Decision Requiring Procurement to Address Mid-Term Reliability (2023-2026)*, R.20-05-003 (June 24 2021), at 75: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603637.PDF (adopting penalty provisions for failure to comply with the MTR procurement, but noting the Commission's ability to "take into consideration good faith efforts" in its imposition of penalties).

9 D.18-05-026, *Decision Implementing Senate Bill 350 Provision on Penalties and Waivers in the Renewables Portfolio Standard Program and Denying Petition for Modification of Decision 17-06-026*, R15-02-020 (May 31, 2018).

10 CPEs are not subject to penalties and can defer procurement to the CAISO if the price for local RA procurement is too high.

11 D.06-06-064, *Opinion on Local Resource Adequacy Requirements*, R.05-12-013 (June 29, 2006), at 71: https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/57644.PDF. Beginning in RA compliance year 2023, only LSEs in SDG&E's service territory will have access to the local RA waiver. LSEs in PG&E and SCE service territories do not have local obligations and, therefore, do not have access to the waiver. The CPEs in PG&E and SCE territories do not face penalties for failure to procure their full local RA obligations.

deficiencies. CalCCA previously requested on three occasions that the Commission adopt a system and flexible RA waiver process similar to the process available for local RA given the current tightness of the RA market. The Commission denied CalCCA's requests for system and flexible RA waivers in D.20-06-031[12], D.20-09-003[13], and D.21-07-014[14], stating that a system and flexible waiver process requires further development and study. CalCCA has not been the only LSE to seek system waivers given tightening capacity market conditions. In its March 22, 2019 comments, Southern California Edison stated:

> With the forecasted tightening supply condition, the potential exercise of market power in System and Flexible RA resources increases. Given the strong linkage among RA products, in particular, between Local RA and System RA, market power issues affecting one product could impact the rest of the RA products. A waiver for Local RA alone, if there is market power for System RA resources, will be insufficient to prevent the exploitation of market power. While LSEs can point to trigger prices for a Local RA waiver, there is no mechanism, let alone a trigger, for System RA. Thus, LSEs would be protected from a non-competitive price for the Local RA attribute of the resource, but would be subjected to a penalty for the very same resource with respect to System RA requirements in a situation in which the resource is pivotal.[15]

The Commission rejected this proposal in D.19-06-026 noting:

> The Commission recognizes the concern that a tightening RA market may necessitate system and flexible RA waivers for circumstances beyond the control of an individual LSE. However, there remain significant, unresolved issues that require further consideration before allowing such waivers, including potential leaning by LSEs and market power issues. Such market power

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[12] D.20-06-031, *Decision Adopting Local and Flexible Obligations and Refining RA Program*, R.19-11-019 (June 25, 2020), at 65: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M342/K083/342083913.PDF.

[13] D.20-09-003, *Decision Denying Petitions For Modification of Decision 19-06-026, Decision 19-02-022, and Decision 20-01-004*, R.17-09-020 (Sept. 10, 2020): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M347/K124/347124261.PDF.

[14] D.21-07-014, *Decision on Track 3B.2 Issues: Restructure of The Resource Adequacy Program*, R.19-11-009 (July 15, 2021): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M393/K334/393334426.PDF.

[15] *Comments of Southern California Edison Company (U 338-E) on The Track 3 Proposals and March 12-13, 2019 Workshop* (R.17-09-020), at 1-2 [footnote omitted].

> issues may include potential gaming by generators that may, for example, withhold capacity during more expensive peak months. While we decline to extend the waiver process beyond local RA at this time, the Commission encourages further discussion of these issues through workshops or in a later phase in this proceeding.[16]

However, the circumstances have changed considerably as described herein since the Commission previously considered whether to allow system and flexible RA waivers and should not preempt Commission consideration of waivers here.

B. The Commission Should Implement a System and Flexible RA Waiver

The Commission should implement a system and flexible RA waiver process that allows LSEs to apply for a waiver by demonstrating reasonable efforts to procure. Current circumstances are similar to those that prompted the Commission to adopt a local RA waiver process, in which the amount of RA supply is insufficient to meet the system RA requirement. These circumstances necessitate a waiver process for system RA to mitigate (1) the exercise of market power by suppliers, and (2) penalizing LSEs for not meeting unmeetable requirements.

Increasing or further exposing LSEs to penalties under the current circumstances will not result in more resources coming online in the near-term. It is the role of the IRP proceeding to ensure new resources get built to increase the supply stack. Once the resources get built through the IRP, it is the role of the RA program to ensure those resources are contracted for and available to serve California load in the short term. LSEs are procuring at record paces to meet procurement orders and policy goals. Procurement ordered in years 2021 through 2028 far surpasses the pace of procurement at any other time in recent years. In fact, the build rate between 2022-2028 is two and a half times higher than the build rate following the post 2000-

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[16] D.19-06-026, *Decision Adopting Local Capacity Obligations for 2020-2022, Adopting Flexible Capacity Obligations for 2020, and Refining The Resource Adequacy Program*, R.17-09-020 (June 27, 2019), at 18: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M309/K463/309463502.PDF.

2001 energy crisis build out from 2002 - 2008.[17] The Commission found that LSEs have been able to meet these aggressive targets despite supply chain issues and interconnection delays, finding that in 2022, LSE met their tranche two requirements and were able to catch up on prior tranches' requirements.[18] As demonstrated by this progress, LSEs are doing all they can to increase the stack as quickly as possible. Still, the RA stack is short for 2023. Increasing penalties in this circumstance will not result in incremental reliability or improve compliance.

C. If the Commission Declines to Adopt a System and Flexible RA Waiver for the Year-Ahead and Month-Ahead Showings, the Commission Should Implement a Waiver Process for Year-Ahead Showings at Minimum

Balancing the capacity shortfalls making compliance difficult and the Commission's reluctance to adopt a waiver for system and flexible RA, CalCCA proposes that the Commission offer a system and flexible RA waiver limited to the year-ahead showings. This would allow the LSE to demonstrate that it took reasonable efforts to procure to meet its 90 percent year-ahead obligation. The Commission would have the discretion to grant the waiver based upon the information provided by the LSE to demonstrate its efforts. Following the year-ahead showings, LSEs would still need to procure to meet their 100 percent month-ahead obligations and would face penalties if they did not meet their month-ahead requirements. LSEs would not have access to a waiver for the month-ahead showings. This proposal would allow LSEs to finalize their procurement in the month-ahead before facing penalties, which is useful given the uncertainty around the availability of imports and hydro capacity in the year ahead. Additional hydro and

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17 Installed capacity values for procurement orders from 2022 through 2028 estimated using California Energy Commission (CEC) assumptions from its *SB 846 – Diablo Canyon Extension and CERIP* Presentation at slide 37 and 38: https://efiling.energy.ca.gov/GetDocument.aspx?tn=248455&DocumentContentId=82897; Installed capacity for prior years can be found here: https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/electric-generation-capacity-and-energy.

18 https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/d1911016andd21.pdf.

import capacity may open up between the year-ahead and month-ahead showings processes as suppliers gain certainty around their available supply. LSEs should be able to use this additional capacity to finalize their procurement before facing penalties given how tight the capacity market is currently. This proposal would also ensure that no LSE is waived of its obligation, as the LSE would still need to make up any deficiencies that it had in the year-ahead prior to the month ahead to avoid month-ahead penalties.

D. The Commission Should Not Apply Points to LSEs with RA Deficiencies who Took Reasonable Efforts to Comply

CalCCA also proposes that the Commission stop applying "points" to LSEs with RA deficiencies. D.21-06-029 adopted a tiered penalty structure in which LSEs face higher penalties the more deficiencies, or points, they accumulate. LSEs with one to five points fall into Tier 1 and pay the applicable RA penalty in $/kW-month; LSEs with six to ten points fall into Tier 2 and pay twice the applicable RA penalty; and LSEs with 11 or more points fall into Tier 3 and pay three times the applicable RA penalty.[19]

To address the challenges with the current capacity landscape, in which some LSEs will be deficient no matter how hard they try to comply, the Commission should refrain from assigning any points for RA deficiencies if LSEs can demonstrate they took reasonable efforts to comply. This ensures LSEs are not *overly* penalized for not meeting their compliance obligations when it may have been impossible for them to comply. It also avoids a perceived shortcoming of the waiver process - that LSEs who comply are effectively penalized for their compliance by paying high prices to comply while other LSEs avoided paying those high prices by receiving a waiver – because LSEs that do not meet their obligations would still pay penalties. Similar to the

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[19] 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.19-11-019 (June 24, 2021), at 57: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603561.PDF.

compliance processes in IRP, RPS, and local RA, LSEs would need to apply to avoid accumulating points by demonstrating good faith efforts to comply. If the Commission decides not to apply points to the LSE with a deficiency, then the Commission should note this on the penalty list, indicating that LSEs took good faith efforts to comply with its requirements.

E. The Commission Should Not Publish LSE Penalty Information that Exposes Market Sensitive Information

Energy Division proposes to publicly publish information regarding LSEs' deficiencies and citations. Specifically, Energy Division proposes to provide the following information for year-ahead and month-ahead deficiencies:

- Type of deficiency;
- Month of deficiency;
- Deficient amount (MW);
- Amount of deficiency as a portion of the LSE's requirement; and
- Any points accrued for system deficiencies.[20]

The Commission should not adopt this proposal. Energy Division erroneously suggests that posting the information after the compliance month avoids revealing market sensitive information.[21] Energy Division's proposal would make public much more granular information than it ever has before. This information would effectively expose LSEs' net position by providing the deficient amount and the deficiency as a percent of the LSE's requirement, along with the type of deficiency, month of deficiency, and points accrued. Net positions are extremely market sensitive and should not be publicized.

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[20] *Administrative Law Judge's Ruling on Energy Division's Phase 3 Proposals*, R.21-10-002 (Jan. 20, 2023) Attachment 2 (Energy Division Proposals), at 29.

[21] *Id.*

This information is market sensitive, even if posted after the compliance month, because it informs the market of the LSE's position as it is continuing to procure for future RA months. For example, assume an LSE is on track to be deficient for the RA months of July, August, and September. Upon filing its July RA showing, the LSE is deficient and the Commission posts the LSE's July deficiency. After posting the deficiency, the LSE would still have time to complete procurement for August and September to close the gap on its anticipated deficiency. However, upon posting of the LSE's July deficiency, the market is made aware the LSE was unable to meet its July obligation and therefore unlikely to have met its August and September obligation. Publicizing this information puts LSEs at a disadvantage because sellers will know the amount the LSE could need in its next month-ahead showing.

Given the market exposure the disclosure would create, Staff's proposal is prohibited by California law. An LSE's net short RA position is protected under the Public Records Act, which exempts from disclosure information otherwise protected by state law.[22] California Code of Procedure section 1040(b)(2)[23] protects the information through its requirement to weigh the benefit of disclosure against the harm that could come to the public. As discussed above, disclosing an LSE's net RA position exposes the LSE and its customers to a potential market power exercise by suppliers in further negotiations for supply yet has no apparent public benefit. Moreover, the Commission's confidentiality rules protect this information from public disclosure for three years. The IOU Confidentiality Matrix adopted in D.06-06-066 exempts the IOU's net short positions;[24] if the information for IOUs cannot be disclosed, Public Utilities Code section 380(e), which requires nondiscriminatory enforcement, prohibits the Commission from

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22 Cal. Gov't Code § 7927.705.
23 Cal. Code Civ. Proc. § 1040(b)(2).
24 D.06-06-066, Appendix 1, § VI.A, at 13.

disclosing this information for other LSEs. Finally, the ESP/CCA confidentiality matrix expressly exempts RA supply data from disclosure.[25]

F. The Commission Should Clarify Energy Division's Penalty Proposal to State That LSEs Will Pay the Penalty Price of the Tier the LSE is in at the Point in Time That the Non-Compliance Event Occurs

Energy Division's Proposal 3 proposes clarifications of the RA compliance and penalty provisions.[26] CalCCA understands Energy Division's proposals to say that LSEs will pay the penalty price of the tier the LSE is in at the point in time that the non-compliance event occurs, and that the Commission will not apply higher penalty prices retroactively to penalties assessed in the year-ahead in the event an LSE enters a new tier in the month-ahead process.

As written, however, the Energy Division Proposal 3 could be interpreted as LSEs' entering a new tier intra-year will pay the new tier's penalty price retroactively for year ahead penalties in addition to month ahead penalties and future years penalties. The Commission should clarify that this is *not* the case, and that LSEs will pay the penalty price of the tier the LSE is in at the point in time that the non-compliance event occurs. For example, assume an LSE is in tier one at the time of its year-ahead filing. The LSE has a year-ahead deficiency for 2023. The LSE should pay the tier one penalty price for its 2023 year-ahead deficiency. Then in the month ahead, the LSE has multiple monthly non-compliance events and enters tier two in the month of August in 2023. The Commission should only require the LSE to pay the tier 2 penalty prices for the August month ahead penalty in 2023 and any future penalties, the Commission should not then retroactively apply the penalty to the 2023 year-ahead penalty already paid at the tier one penalty price. In sum, the Commission should clarify Energy Division's penalty proposals to state that LSEs will pay the penalty price of the tier they are in at the point in time

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[25] D.08-04-023, Appendix B, § II.B., at 2 (adopted for CCAs in Ordering Paragraph 5 of D.20-07-005).

[26] Energy Division Proposals at 26-27.

that the non-compliance event occurs, and that the Commission will not retroactively apply higher tiers to penalties already assessed.

V. STAFF'S PROPOSAL TO PROHIBIT LSE EXPANSION FOR RA NON-COMPLIANCE OVERSTEPS THE COMMISSION'S LEGAL AUTHORITY

Energy Division Staff proposes to prohibit LSEs' expansions if they have "not met their RA obligations at current levels of load."[27] Staff justifies this proposal on grounds that expansion "will jeopardize reliability if these LSEs fail to procure their full RA obligations in the future with increased levels of load."[28] As discussed in section VI, this proposal is arbitrary and adds no incremental reliability value. Moreover, Staff's proposal lies outside the bounds of the Commission's jurisdiction.

A. Assembly Bill (AB) 117 Did Not Confer Authority on the Commission to Determine Whether a City, County, or Joint Powers Authority Forms a CCA or Expands Its Scope

AB 117 did not grant the Commission jurisdiction to authorize or prohibit a city, county, or joint powers authority from engaging in community choice aggregation. Indeed, the Legislature conferred the right to make decisions about CCA formation to those state governmental subdivisions and their residents, <u>not</u> to the Commission. This legal conclusion aligns directly with the Commission's own prior legal interpretation.

AB 117 authorizes a city, county, or joint powers authority "to aggregate the electrical load of interested electricity consumers within its boundaries…."[29] The statute requires that this local choice be made through the passage of a local ordinance.[30] The only express prohibitions deny CCAs the right to serve load served by a local publicly owned utility[31] and to serve

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27 Energy Division Proposals, Proposal 5 at 34.
28 *Ibid.*
29 Cal. Pub. Util. Code § 366.2(c)(1).
30 *Id.* at § 366.2(c)(10).
31 *Id.* at § 366.2(c)(1).

customers without the Commission's prior determination of departing load costs.[32] The statute confers no Commission authority to approve a CCA's implementation, but only to "certify that it has received the implementation plan" prepared by the CCA pursuant to statutory requirements.[33] As the Commission itself determined: "AB 117 does not provide us with authority to approve or reject a CCA's implementation plan or to decertify a CCA."[34]

Indeed, the statutory scheme gave the Commission limited roles and responsibilities, as it noted in Decision 05-12-041.[35] Generally, these include:

1) imposing a cost-recovery surcharge;
2) notification to the utility of its intent to serve customers;
3) ensuring that a CCA's implementation plans and program elements "are consistent with utility tariffs and consistent with Commission rules designed to protect customers;"
4) adopting customer protections around termination, payments and deposits, and customer notifications;
5) adopting policies for customer enrollment, scheduling coordination, call center operations, boundary meters, and customer switching;
6) establishing service fees for utility services;
7) ensuring California Alternate Rates for Energy (CARE) benefits are provided to CCA customers; and
8) applying the RPS.

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32 Cal. Pub. Util. Code § 366.2(c)(8).

33 *Id.* at § 366.2(c)((7) (emphasis added).

34 *See* 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), at 4: https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/52127.PDF.

35 *Id.* at 3-5. The Commission found it has authority to assert limited jurisdiction over CCA matters, noting the following list: (1) imposing a cost-recovery surcharge, (2) notification to the utility of its intent to serve customers, (3) ensuring that a CCA's implementation plans and program elements "are consistent with utility tariffs and consistent with Commission rules designed to protect customers," (4) adopting customer protections around termination, payments and deposits, and customer notifications, (5) adopt policies for customer enrollment, scheduling coordination, call center operations, boundary meters, and customer switching; (6) establish service fees for utility services, (7) ensure CARE benefits are provided to CCA customers, and (7) apply the RPS.

The Commission also noted in D.05-12-041 its role in applying resource adequacy requirements. Again, however, the Commission's interpretation provided no foundation for authority to prohibit expansion by a CCA.

AB 117 provides no authority—express or implied—for the Commission to determine when and whether a city, county, or joint powers authority could form a CCA. All signs point to the contrary. Lacking authority over CCA formation leaves the Commission likewise lacking authority when an existing CCA proposes to expand as a vehicle for a new CCA to form.

B. The Commission's RA Authority Does Not Allow It to Prohibit Expansions for Non-Compliance

The Commission lacks authority under AB 117 to prohibit CCA formation or, by extension, CCA expansion. The Commission's RA authority under Section 380, while permitting enforcement, does nothing to expand its jurisdiction over CCAs.

The Commission recognizes its statutory authority over CCA resource adequacy in D.05-12-041.[36] Section 380 allows the Commission to establish RA requirements for all LSEs,[37] including CCAs. The statute also allows the Commission to "exercise its enforcement powers to ensure compliance by all load-serving entities."[38]

Despite recognizing its RA authority in D.05-12-041, the Commission declares that it has no authority "to approve or reject a CCA's implementation plan or to decertify a CCA."[39] Section 380, while giving Commission authority over RA requirements and compliance, does not by the Commission's own admission extend its authority over CCA formation or expansion.

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36 D.05-12-041 at 3.
37 Cal. Pub. Util. Code § 380(a).
38 *Id.* at § 380(e).
39 D.05-12-041 at 4.

C. The Commission's Authority to Designate the Earliest Possible Effective Date for a CCA Program Does Not Permit a Prohibition on Expansion for Failure to Meet RA Requirements

Public Utilities Code section 366.2(c)(8) permits the Commission to designate the earliest possible effective date for implementation of a community choice aggregation program. That right, however, may only be exercised "taking into consideration the impact of any annual procurement plan of the electrical corporation that has been approved by the commission." RA non-compliance by an LSE has nothing to do with a utility's procurement plan.

In fact, the Commission addressed this statutory provision in adopting Resolution E-4907. In Resolution E-4907, the Commission set a single start date/timeline for all new and expanding CCAs who submit implementation plans beginning in 2018. The Commission's action had nothing to do with non-compliance by a CCA but arose from the potential for cost shifting from departing load to bundled customers[40] -- a central area of Commission responsibility under AB 117. The Commission concluded that without a new timeline, a utility may have already procured RA for the CCA departing customers but such costs would not be reflected in the departing customers' Power Charge Indifference Adjustment. This timing mismatch would result in bundled customers paying the RA costs attributable to the departing load. For this reason, the Commission concluded: "Although Resolution E-4907 may delay some CCAs' desired date to begin service, any such delay would be for a finite period and for the purpose of avoiding unlawful cost shifting."[41]

The utilities' procurement plans are not at issue in the Staff's expansion prohibition proposal, and Section 366.2(c)(8) cannot be used to justify the proposal.

[40] Resolution E.4907 at 7.
[41] Resolution E-4907, at 15 (citing 366.2(c)(8)).

D. Prohibiting CCA Expansion Would Result in a Discriminatory Application of the Commission's Section 380 Enforcement Authority

Section 380 requires that the Commission "implement and enforce the resource adequacy requirements….in a nondiscriminatory manner."[42] The Commission's proposal to enforce its RA requirements through a prohibition on "LSE" expansion discriminates against CCAs.

Today, CCAs are the only entities entitled to "expand" their service. While IOUs may add new load to their service territories, their territories have been fixed for decades and are not subject to further expansion. Similarly, the Commission recommended to the Legislature against further Direct Access expansion in D.21-06-033[43]. Consequently, the proposal to prohibit "LSE" expansion effectively means to prohibit "CCA" expansion, since the rule would not have equal effects on all categories of LSEs. Consequently, even if the Commission's enforcement authority could be viewed more broadly than the RA program reaches today, enforcing the requirements through the proposed expansion prohibition would constitute a discriminatory application of its enforcement powers.

VI. ENERGY DIVISION'S LSE EXPANSION PROPOSAL IS ARBITRARY AND ADDS NO INCREMENTAL RELIABILITY VALUE

During a time where the ability to obtain sufficient capacity to meet reliability needs is in question, not due to an LSE's lack of effort but due to the availability of capacity in an increasingly capacity constrained market and growing demand for capacity in the WECC, the concentration on actions to be taken against CCA and Electric Service Provider (ESP) providers is misguided. In particular, the Energy Division staff proposal to halt expansion of a CCA or ESP for an RA non-compliance event without consideration of all of the factors, including capacity

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42 Cal. Pub. Util. Code § 380(e).

43 D.21-06-033, *Decision Recommending Against Further Direct Access Expansion*, R.19-03-009 (June 24, 2021): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M390/K215/390215673.PDF.

available in the market, is illogical as described in this section. Further, a response provided by Energy Division staff to a question about the expansion proposal at the February 8, 2023 workshop revealed the prejudicial nature of the proposal. That is, when asked if this would be applied to all LSEs including a non-compliance by an IOU, Energy Division staff responded that if no LSE including the IOUs were able to meet their RA compliance targets, then all load migration should be halted. Based upon this response, it appears the Energy Division would prefer that the IOUs have responsibility for load even if the IOU is not able to meet compliance targets.

A. CCAs Are Exceeding Mid-Term Reliability Procurement Targets

The Commission recently released the results of Tranche 1 (online by 8/1/21) and Tranche 2 (online by 8/1/22) procurement to meet IRP procurement obligations set by D.19-11-016.[44] Pages 24 and 25 of the presentation from the Commission are very telling.[45] Cumulatively, Tranche 1 fell short of the target by 366 MWs where that shortfall was caused by the three IOUs coming up 411 MWs short of their targets while the CCAs and ESPs were 20 MWs and 25 MWs in excess of their targets. The presentation notes that all LSEs except PG&E and SDG&E had caught up with Tranche 1 obligations by 2/1/2022. For Tranche 2, none of the three IOUs met their obligations by the 8/1/22 online date and were cumulatively 22 percent short with a total of 381 MWs deficient. Of the other LSEs, only one was unable to meet its full need by the obligation date and that LSE was 8 MWs short of a 75 MW requirement or just under 11 percent. The Commission's presentation indicates that, "[e]ven though the IOUs did not

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[44] D.19-11-016, *Requiring Electric System Reliability Procurement for 2021-2023*, R.16-02-007 (Nov. 7, 2019): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M319/K825/319825388.PDF.

[45] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/d1911016andd21.pdf.

meet Tranche 2 on time, LSEs were collectively able to meet Tranche 2 on time (and "catch up" on the Tranche 1 requirements) due to excess procurement by the CCAs and ESPs."[46]

Given the shortages of capacity available to the grid, the CCAs and ESPs should be recognized for their ability to not only meet their obligations but exceed them in a manner that made up for the shortfall of the three IOUs. This stands in stark contrast to the proposed vilification of the CCA and ESP LSEs with the proposal to halt any expansion due to RA non-compliance, regardless of whether those entities made commercially reasonable efforts to procure but were unable to due to market conditions for capacity within the WECC.

B. Expansion By Non-Compliant LSEs Does Not Increase the Supply or Load

To the extent a CCA or ESP is taking on existing customers of the IOU, the expansion of either is a zero-sum game with respect to load. That is, a customer migrating from the IOU to a retail provider neither increases nor decreases their load. It simply means that a different entity will be responsible for the capacity and energy needs of the customers. In fact, to this very point, there are processes to address this very concern.

C. IOU Share of Departing Load Resources are Made Available to the Serving LSE Before Launch

There is a process in load migration that allows the LSE losing load to enter into a transaction with the LSE gaining load to transfer the RA capacity such that the LSE losing load is able to monetize the value of its now excess capacity to reduce costs to its remaining customers while the load gaining LSE has access to capacity necessary to meet its customers' needs. Given such a process and the zero-sum nature of the load migration process with regard to its impact on capacity, there is no logical reason to disallow load migration when the cause of a

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46 *Id.* at slide 24.

non-compliance is likely a lack of capacity available to the market and not the lack of action on the part of the non-compliant LSE.

D. Limiting LSE Expansion Does Not Address the Lack of Capacity in the RA Market

As discussed in section III, CalCCA contends that given the stack analysis it has performed, the lack of clarity in the availability of capacity in California and the WECC, and increased competition for limited capacity, limiting LSE expansion does nothing to cure the underlying issues. The lack of capacity faced by jurisdictional LSEs has created a game of musical chairs. Without enough capacity (i.e., chairs) at least one, and likely several, LSE(s) is (are) likely to find themselves in non-compliance. As is clearly evident, halting LSE expansion does not get new resources built. Since CCAs and ESPs were successful in the development of new resources to meet D.19-11-016, which <u>does</u> increase the supply of available capacity, it is not clear why the Commission would want to limit their expansion.

E. Energy Division's Use of the Phrase "Any New Load" and "New Customers" is Ambiguous

At page 37 of the Energy Division's proposal, staff states:

> To address the potential reliability issues that arise with continued expansion of LSEs that are failing to meet their current summer RA obligations, ED staff propose that a community choice aggregator (CCA) or electric service provider (ESP) <u>must be in good standing in meeting its RA requirements in order to take on new customers.</u> (emphasis added)

On the same page Energy Division staff propose:

> Specifically, ED staff proposes that any CCA or ESP with a deficiency of greater than 2.5% of its system RA requirement on a month ahead RA filing during the previous two calendar years <u>should not be able to expand and take on new any new customer load</u> for the following year. (emphasis added)

As discussed in sections VI A though D, CalCCA disagrees with the concept and effectiveness of such a prohibition. That notwithstanding, the language used by Energy Division Staff is vague and potentially overly broad. First, any application of this provision should not become retroactive. That is, the expansion of a CCA is a lengthy process that must follow Public Utilities Code section 366.2. This section has a process for the CCA to notify the Commission and for plans to be made to transition the customers and responsibility for the customers energy and capacity needs to the CCA.

Despite this clear process which begins long before the CCA begins serving those customers, the Energy Division staff proposal says nothing of when the prohibition on expansion would occur. This is detrimental to the CCA, the IOU, and the customer as the timeline defined in the CCA implementation plan is relied upon by both the CCA and the IOU to plan for and execute on a procurement strategy and action. For this reason, the proposal must clarify that such prohibition would only occur on expansion that have not already been noticed through an implementation plan under Public Utilities Code section 366.2.

Additionally, the language used by Energy Division staff in their proposal could be interpreted to mean that a CCA cannot serve any new load within their existing service area. This could then mean that any customer new to an existing premise or any new premise built within the service area of a CCA would be required to opt-out of CCA service. Additionally, a stronger interpretation could mean that no CCA customer could add additional load to their premise unless they opt-out of CCA service. Each of these results are excessive. Therefore, Energy Division staff should clarify that their proposal does not apply to the already established service area of the CCA.

VII. ENERGY DIVISION'S RA IMPORT PROPOSALS WILL DIMINISH THE AVAILABILITY OF RA IMPORTS IN AN ALREADY CONSTRAINED MARKET

To address concerns around speculative import supply, the Commission authorized a firm energy requirement for RA imports in D.20-06-028.[47] The Decision requires non-resource-specific imports to self-schedule or bid at levels between negative $150/ megawatt-hour (MWh) and $0/MWh during the availability assessment hours. The adoption of this requirement has resulted in significant unintended consequences as capacity across the west has become increasingly constrained. Because of this, the Commission must reconsider the firm energy import RA requirement in its entirety. Energy Division's proposal, however, advances modifications to the original firm energy requirement to strengthen it further by replacing the bidding requirement with an energy must flow requirement and requiring LSEs to be the scheduling coordinator for their non-resource specific RA imports.[48]

Energy Division's proposal moves in the wrong direction for several reasons. Requirements that limit the ability of import RA resources to recover their costs through the energy market have limited California LSEs' ability to contract with imports. This is because imports have multiple opportunities to sell their capacity and LSEs must compete with non-Commission jurisdictional LSEs who have the same need for capacity but do not have the same stringent bidding requirements. Given the west-wide capacity constraints, importers are likely willing to forego selling their capacity to Commission-jurisdictional LSEs to sell elsewhere. Additionally, many LSEs are not their own scheduling coordinator due to their size or the operational costs associated with taking on those services. These LSEs rely on third parties to

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[47] D.20-06-028, *Decision Adopting Resource Adequacy Import Requirements*, R.17-09-020 (June 25, 2020): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M342/K516/342516267.PDF.

[48] Energy Division Proposal at 37.

schedule their load and resources. Requiring these LSEs to become scheduling coordinators for their import RA contracts would effectively rule out their ability to contract with RA imports. RA import requirements can and should be effectuated through existing mechanisms: contract provisions and after-the-fact assessments of whether or not resources performed as required.[49]

Rather than modifications to the status quo, the Commission must consider wholesale revisions that balance the critical need for access to additional RA capacity while also addressing the Commission's concerns around speculative supply. CalCCA's proposal balances these needs by allowing resources to bid their costs without allowing bids so high the bid price is unlikely to ever be struck. This should incent import RA providers to have physical supply backing their RA commitment given the high likelihood their bid will clear. In summary, the Commission should reject Energy Division's proposal to include an energy must flow requirement and require LSEs to be the scheduling coordinator for their non-resource specific RA imports and instead adopt CalCCA's proposal to allow RA imports to bid up to a maximum bid price based upon estimated fuel, variable operation and maintenance, and GHG costs.

VIII. THE COMMISSION SHOULD RESTRUCTURE THE EFFECTIVE PRM SO THAT IT IS TRULY INCREMENTAL TO RA RESOURCES

In the Summer Reliability Proceeding (R.20-11-003), the Commission adopted an effective PRM to bring online additional resources needed for reliability during extreme events. The effective PRM required the investor-owned utilities (IOUs) to procure additional resources on top of the 15 percent PRM with costs allocated to all customers. In the first phase of the proceeding, the Commission adopted a 17.5 percent effective PRM. In the second phase, the

[49] D.21-06-029 at 63.

Commission adopted a 20-22.5 percent effective PRM that extended through 2023.[50] D.22-06-050[51] adopted a 16 percent PRM for 2023 and a 17 percent PRM for 2024 subject to additional LOLE modeling by Energy Division. This modeling recommends a PRM of 18-20 percent, based on the modeled generation fleet and updated CEC load profiles.[52] Based upon this modeling, Energy Division's proposal identifies four options for the 2024 PRM, any of which could be accompanied with an extension of the effective PRM. Of the four options presented, Energy Division recommends maintaining the 17 percent PRM adopted in D.22-06-050 and adopting an effective PRM through 2025 to cover the difference between the modeled PRMs and the 17 percent PRM already adopted.

The Commission should adopt this proposal only if the resources eligible to count towards the effective PRM are truly incremental to the RA stack. The effective PRM adopted in the Summer Reliability Proceeding allows both RA and non-RA eligible resources to count towards the effective PRM. The IOUs have used RA-eligible resources for the effective PRM, taking resources away from the pool of resources other LSEs could have used to meet their own PRM compliance obligations. CalCCA analyzed the Advice Letters filed by the IOUs documenting their procurement for the effective PRM and found that the IOUs relied on 1,858 MWs of RA-eligible resources to meet their effective PRM requirements for July 2023, as

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50 D.21-12-015, *Phase 2 Decision Directing Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company to Take Actions to Prepare for Potential Extreme Weather in The Summers of 2022 and 2023*, R.20-11-003 (Dec. 2, 2021): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M428/K821/428821475.PDF.

51 D.22-06-050, *Decision Adopting Local Capacity Obligations for 2023 - 2025, Flexible Capacity Obligations for 2023, and Reform Track Framework*, R.21-10-002 (June 23, 2022): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M488/K540/488540633.PDF.

52 *Administrative Law Judge's Ruling on Energy Division's Phase 3 Proposals*, R.21-10-002 (Jan. 20, 2023) Appendix B: Loss of Load Expectation and Slice of Day Tool Analysis for 2024:https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M501/K409/501409211.PDF.

demonstrated in the stack analysis presented in section II. These resources include firm energy imports, additional RA contracts or RA contract extensions, and tolling agreements.[53]

Allowing RA eligible resources to count towards the effective PRM adds competing demand for RA supply. When the available supply is not sufficient to meet the PRM itself, as experienced in 2023, adding an effective PRM does not result in incremental reliability. Instead, it only increases the ability of suppliers to exercise market power and exacerbates challenges LSEs face in meeting their own RA requirements. If the effective PRM is extended through 2025, the Commission must revise the list of eligible resources to include only those that do not already qualify for RA, like the Emergency Load Reduction Program (ELRP). This would avoid one LSE procuring above and beyond their own RA obligation to meet an effective PRM while another LSE remains short on their base PRM obligation.

While the effective PRM process has required IOUs to make "reasonable attempts" to sell excess capacity to other LSEs before using it for the effective PRM,[54] the Commission must recognize that IOUs in the market attempting to procure RA puts upward pressure on demand, increasing market prices for all. Presumably, if the IOU does sell its excess position to other LSEs, they will do so without taking a loss and this will simply result in an increased cost to consumers to procure the same resources that could have been accomplished at lower cost without the IOU intervention.

[53] For a detailed description of CalCCA's analysis of IOU Advice Letters to determine the amount of Summer Reliability procurement that came from RA-eligible resources, see Appendix B.

[54] D.21-12-015, *Phase 2 Decision Directing Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company to Take Actions to Prepare for Potential Extreme Weather in the Summers of 2022 and 2023*, R.20-11-003 (Dec. 2, 2021), at 103.

IX. THE COMMISSION SHOULD ALIGN RESOURCE MODELING AND COUNTING WITH RESOURCE CAPABILITIES

Energy Division proposes a methodology for derating thermal power plants based on forecast ambient temperatures using forced outage data from the CAISO.[55] Although this proposal will better align the modeling that sets RA requirements with the capabilities of the RA fleet, this proposal does not extend to resource counting rules, creating a potential mismatch between modeling and resource counting. This is because forced outage impacts need to either be included in the PRM as a buffer or in resource counting through a derate. If resource counting does not include forced outage impacts, then the PRM includes a buffer for forced outage impacts. If resource counting does include forced outage impacts, then a buffer is not needed in the PRM.

To ensure there is not a misalignment between the PRM and resource counting, the Commission should continue its pursuit of an unforced capacity (UCAP) counting methodology to account for resources' forced outages in their RA accounting. A UCAP counting methodology would align modeling with RA counting *and* provide the right incentives for resources to provide maintenance such that they can be available and reliable during times of system need. A UCAP methodology that incorporates a range of forced outage types, including ambient derates, plant trouble, and other forced outage types, will provide the market with transparency about the reliability value RA resources provide.

The current RA program does not incent resources to minimize forced outages. When resources experience forced outages, they must provide substitute capacity or face charges through the Resource Adequacy Availability Incentive Mechanism (RAAIM). The RAAIM penalty price is currently 60 percent of the $6.31 per kW-month capacity procurement mechanism (CPM) soft

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55 Energy Division Proposals, Attachment 4.

offer cap,[56] which is far lower than what resources can expect to receive through RA payments or pay for substitution. This means RA resources may prefer to continue to sell RA rather than properly maintain the resource to avoid forced outages. The consequences of this structure are evident. From 2019 to 2021, average annual forced outage rates have been increasing, from 6.53 percent in 2019 to 7.95 percent in 2021. [57] Aligning PRM modeling with RA resource counting by including forced outage impacts in resources' qualifying capacity values will ensure the Commission sets requirements at a level that meets reliability targets, sets resource accounting according to resource capabilities, and incents resources to minimize forced outages.

X. THE COMMISSION SHOULD PRIORITIZE RESOURCE DEVELOPMENT AND CONSIDER MULTI-YEAR RA PROPOSALS IN CONCERT WITH THE PROCUREMENT PROGRAM IN DEVELOPMENT IN THE IRP PROCEEDING

The Alliance for Retail Energy Markets' (AReM's) proposal mirrors its proposal in the IRP proceeding, which puts forth a four-year forward RA obligation for system RA to incentivize new resource development.[58] AReM indicates that its proposal would not stand alone without IRP programmatic procurement reform.[59] The Commission must contemplate whether or not to implement multi-year RA requirements in concert with the development of the procurement program in the IRP proceeding. As CalCCA's analysis in section II demonstrates, the Commission must prioritize getting enough new capacity developed and online such that there are sufficient resources available for LSEs to meet their RA compliance obligations. It is the role of the IRP program to get <u>*new*</u> resources online, while it is the role of the RA program to

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[56] CAISO Tariff Section 40.9.6.1(b): http://www.caiso.com/Documents/Section40-ResourceAdequacyDemonstration-for-SchedulingCoordinatorsintheCaliforniaISOBalancingAuthorityArea-asof-Feb11-2023.pdf.

[57] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/workshop-9-ucap-proposal_caiso.pdf at slide 9.

[58] *Implementation Track Phase 3 Proposal of the Alliance for Retail Energy Markets*, R.21-10-002 (Jan. 20, 2023) (AReM Proposal).

[59] AReM Proposal at 2.

retain *existing* resources.[60] Given RA capacity market tightness impacting the ability to meet RA requirements, the Commission must prioritize developing a programmatic approach to procurement to get new resources developed in a timely and orderly manner outside of ad hoc procurement orders. The Commission may couple that program with RA enhancements to support the retention of existing resources but the Commission's priority must first and foremost be how to increase the amount of capacity on the system to serve California load.

Finally, the Commission must consider how multi-year RA requirements interact with other RA program elements, including CPE and cost allocation mechanism (CAM) allocations to LSEs. These allocations need to be allocated to LSEs with sufficient time for LSEs to plan their procurement in alignment with their muti-year requirements.

XI. THE COMMISSION SHOULD NOT LOCK IN YEAR-AHEAD LOAD FORECASTS FOR SETTING RA REQUIREMENTS; DOING SO WOULD RESULT IN INACCURATE REQUIREMENT ALLOCATION

Energy Division proposes that the Commission and parties consider locking in year-ahead load forecasts to use for the RA program, obviating the need monthly load forecast updates and reducing administrative burden.[61] The Commission should not adopt this proposal. Load migrates between LSEs in multiple directions throughout the year. Locking in load forecasts year ahead will create inaccuracies in requirement allocation as load moves among LSEs but requirements stay static. The Commission should continue to require LSEs to submit monthly load forecast updates to ensure accurate allocation of RA requirements.

[60] CalCCA's framework put forth in its December 12, 2022 comments to the September 8, 2022 Ruling in the IRP proceeding (R.20-05-003) allows for the development of RA enhancements to ensure retention of existing resources: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M499/K887/499887293.PDF.

[61] Energy Division Proposal at 35-36.

XII. THE COMMISSION SHOULD ALLOCATE ALL CAM RESOURCES BY MCC BUCKET, RATHER THAN ACROSS ALL BUCKETS EVENLY AND UPDATE THE MCC DATASET

PG&E proposes that "…credited LSE RA requirements continue to be reduced as they are today, but that their MCC bucket category requirements and caps would change based on the mix of resources in the CAM-eligible credits (i.e., their MCC bucket limits would change to reflect the proportional impact of credited CAM-eligible resources)."[62] CalCCA interprets PG&E's proposal as applying to *all* CAM resources, not just CAM resources of a specific technology type or MCC bucket category. Under this interpretation, CalCCA supports this change. Per D.22-06-050, Energy Division already has the discretion to consider CAM credits by MCC bucket when determining compliance with MCC Bucket requirements, if necessary.[63]

CalCCA agrees with PG&E that updating the MCC bucket to include the most recent dataset is reasonable and will be more reflective of the recent stressed summer days.[64]

XIII. CONCLUSION

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

Respectfully submitted,

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CALIFORNIA COMMUNITY CHOICE ASSOCIATION

February 24, 2023

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[62] *Implementation Track - Phase 3 Proposals of Pacific Gas and Electric Company (U 39 E)*, R.21-10-002 (Jan. 20, 2023), at 3.

[63] *Decision Adopting Local Capacity Obligations For 2023 - 2025, Flexible Capacity Obligations For 2023, and Reform Track Framework*, R.21-10-002 (June 23, 2022) (D.22-06-050), at 113.

[64] *Supra* note 53 at 2.

APPENDIX A
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON ASSIGNED COMMISSIONER'S AMENDED SCOPING MEMO AND RULING

Sources And Explanation of The RA Stack Analysis (Figure 1)

Figure 1 uses both familiar data in assessing RA supply sufficiency but also integrates information not typically considered in a supply analysis. This information, reflected in rows 11 through 13, stems from regulatory changes implemented by the Commission that had the effect of eroding supply available to other LSEs. The table below documents the sources of data used in Figure 1.

Row(s)	Source
1-4	California ISO NQC List. The CAISO lists the net qualifying capacity (NQC) for all resources in the CAISO footprint for 2023.[65] We identify the plant owner by matching the resource identification number (resource ID) in the NQC list to the resource ID in the CAISO Master Generating List.[66] Three companies (Calpine, AES, and NRG) and their affiliates own nearly 12 GW (over 20%) of NQC.
5	Thermal Plant Derate. Many thermal generators cannot produce maximum output at certain temperatures, leading to plant derates. For this reason, resource owners may not sell their full NQC as RA capacity. For thermal plants whose NQC is listed as equivalent to their Net Dependable Capacity, we apply a technology-specific thermal derate estimated from historical ambient temperature derates within the CAISO.[67] Our approach parallels recent CPUC discussions regarding the need to include thermal derates in reliability modeling.[68]
6	Imports. Imports reflect the CEC's assumed RA imports available to the CAISO market.[69]

65 CAISO 2023 NQC List: https://www.caiso.com/Documents/2023-net-qualifying-capacity-values-for-resource-adequacy-resources.html.

66 CAISO Master Control Area Generating Capability List at: oasis.caiso.com.

67 Ambient derate data can be found in the CAISO's daily Curtailed and Non-Operational Generator Prior Trade Date Reports: http://www.caiso.com/market/Pages/OutageManagement/CurtailedandNonOperationalGenerators.aspx.

68 ED Staff Proposal for Derating Thermal Power Plants based on Ambient Temperature: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/r21-10-002/4_ed-proposal-for-phase-3-derates.pdf.

69 Joint Agency Reliability Planning Assessment - SB 846 Quarterly Report and AB 205 Report at 43: https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=21-ESR-01.

Row(s)	Source
7	Event-Based Demand Response. Demand response quantities are from the CPUC's Resource Adequacy Compliance Materials.[70] Demand response totals include avoided losses and are from event-based programs at PG&E, SCE, and SDG&E.
9	CAISO 1-in-2 Load Forecast. Monthly peak demand forecast for a median (1-in-2) weather year from the CPUC.[71]
10	Planning Reserve Margin per CPUC D.22-06-050.
11	D.21-12-015, allowed for, "excess resources from an IOU's *existing* portfolios may be used to meet or supplement these procurement targets up to the upper end of its contingency procurement target."[72] Line 11 represents the total of the three IOUs' excess resources from their portfolios as filed in the IOU 2022 Excess Resources Report.[73]
12	D.21-12-015 authorized the IOUs to "continue their procurement efforts and endeavor to meet and exceed their respective incremental procurement targets to achieve the range of additional procurement authorized in this decision for months of concern… As noted previously, a combination of RA eligible and non-eligible resources will be used to meet the contingency procurement target range."[74] While these resources were intended to be incremental to supply available to LSEs to meet their 16% requirement, a significant amount appears to erode existing supply.[75] This erosion occurs because many of the resources are qualified to provide RA and, were it not for the IOU procurement, could provide RA to other LSEs to meet their RA compliance requirements.[76]

[70] 2023-2025 Demand Response Totals available at: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-compliance-materials.

[71] CPUC's 2023 Forecast Summary Tables available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/ra-2023-forecast-summary-tables.xlsx.

[72] D.21-12-015 at 103.

[73] https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-compliance-materials.

[74] D.21-12-015 at 101-102.

[75] The additional resources procured under this authorization are described in the CPUC's RA materials with additional detailed provided in advice letters filed by the IOUs. 2022 IOU Excess Resource reports: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-compliance-materials.

[76] CalCCA used the amounts in the IOU reports and removed those resources that would not otherwise qualify for RA (e.g. ELRP). The resources included in row 12 include, firm energy imports, additional RA contracts, tolling agreements, extension of existing contracts that are RA eligible, and contracts for increased output where the efficiency upgrades likely could have been financed by an RA contract with an LSE.

Row(s)	Source
13	Retention for substitution. IOUs are entitled to retain RA beyond their bundled needs for substitution during planned outages. While 2022 data are not yet available, this assessment relies on the 2021 resources retained by IOUs as reported in the 2021 IOU Excess Resource reports.[77]
14	Expected new-build resources online by 8/1/23. Resources mandated by the CPUC pursuant to D.19-11-016 and D.21-06-035 assuming a 40% delay and/or failure rate.

77 https://www.cpuc.ca.gov/industries-and-topics/electricalenergy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-compliancematerials.

APPENDIX B
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON ASSIGNED COMMISSIONER'S AMENDED SCOPING MEMO AND RULING

Description of Elements in the IOU Resources to Meet Above the Minimum PRM and How They Compete with other LSEs Meeting their RA Requirements

Lines 11 and 12 of the CalCCA stack analysis represent resources that the IOUs were ordered in D.21-12-015 to procure or retain in order to meet an effective PRM above the RA mandated PRM. In researching these resources and the documentation provided by the IOUs, CalCCA has concluded that much of it could be used by LSEs to meet their own RA requirements. While the IOUs may sell excess positions, if the 2022 list of resources described below are retained by the IOUs to meet an effective PRM, it will compete with the ability of other LSEs to meet their RA obligations.

CalCCA Stack Analysis line 11

This line represents the amount of RA by month in the IOUs portfolio that was retained by the IOU and used to mee the effective PRM. Since these are RA resources, they could be used by other LSEs to meet their RA obligation if made available.

CalCCA Stack Analysis line 12

D.21-12-015 states:

> As noted previously, a combination of RA eligible and non-eligible resources will be used to meet the contingency procurement target range. All RA eligible resources supporting the effective PRM should be included in supply plans and IOUs' month ahead RA showings…[78]

In reviewing the reports submitted to the Commission by the three IOUs[79] and the Advice Letters referenced in that report, CalCCA has concluded that a significant portion of those resources would otherwise qualify as RA and could be used to meet RA obligations by other LSEs. The details of those resources procured by the IOUs pursuant to D.21-12-015 which compete for RA capacity are detailed in the table below.

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[78] D.21-12-015 at 102.

[79] https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-compliance-materials 2022 Excess Resource Report.

PG&E	Project/Resource Name	Resource Type	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Advice Letter and/or Resolution
Reference	**1. Supply-Side Emergency Reliability OIR Procurement -** *Itemize each new project/resource by name*	*Indicate whether the resource is new build, firm import, short-term energy only call option, etc.*	*MW to be claimed for CAM Cost Recovery*					*List # if applicable*
1	Import RA: PowerEx	Firm Import	125.00	125.00	125.00	125.00		
2	Import RA: PowerEx	Firm Import	75.00	75.00	75.00	75.00		AL-6504
3	Import RA: PowerEx	Firm Import	200.00	200.00	200.00	200.00		
4	Import RA: Morgan Stanley	Firm Import	50.00	50.00		41.00	100.00	
5	Import RA: TransAlta	Firm Import		50.00	50.00	50.00	50.00	
6	Import RA: Guzman Energy LLC	Firm Import				25.00		
7	Import RA: Dynasty Power Inc.	Firm Import				25.00		
8	Import RA: BPA	Firm Import				100.00		

SDG&E	Project/Resource Name	Resource Type	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Advice Letter and/or Resolution
Reference	**1. Supply-Side Emergency Reliability OIR Procurement -** *Itemize each new project/resource by name*	*Indicate whether the resource is new build, firm import, short-term energy only call option, etc.*	*MW to be claimed for CAM Cost Recovery*					*List # if applicable*
9	Wind and storage incremental		35	35	35	35	35	4010-E

SCE	Project/Resource Name	Resource Type	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Advice Letter and/or Resolution
Reference	**1. Supply-Side Emergency Reliability OIR Procurement -** *Itemize each new project/resource by name*	*Indicate whether the resource is new build, firm import, short-term energy only call option, etc.*	*MW to be claimed for CAM Cost Recovery*					*List # if applicable*
10	Berry Co-gen option		34.00	34.00	34.00	34.00	34.00	*4787*
11	Watson (though 2026)		305.00	305.00	305.00	305.00	305.00	*4767*
12	Gas tolling arrangement expires in 2023		59.00	59.00				*4415*
13	Reliability OIR Procurement (w/o IARs)					35.00		*D.21-12-015*
14	Reliability OIR Procurement (with IARs)					75.00		*D.21-12-015*

<u>Line Reference</u>

PG&E

1, 3-8 – The report provides no advice letter to better understand the nature of the agreement including whether the contracts continue beyond 2022. However, since the resources are described as Firm imports and since the CPUC requires non-resource specific imports to be firm energy to qualify to meet RA, any procurement of firm energy will reduce the pool of remaining firm energy imports available from suppliers.

2 - Like the line above, this resource is no longer available to other LSEs as it is a Firm Import. Unlike the line above, this import is shown in AL-6504 as expiring September 2024.

SDG&E

9 - Represents two wind generation facilities that according to AL 4010-E, with RA only contracts that are in effect for 12 years (25 MW facility) and 14 years (10 MW facility) starting August 1, 2022.

SCE

10 - Represents an extension of a contract through December 2022 with SCE having a unilateral right option to extend for one additional year. This resource does qualify as RA prior to the contract extension.

11 - Represents a 51 month contract with an RA eligible resource through September 2026. While the Advice Letter states the resource was at risk of retirement, a similar offer to procure the RA could have been made by any entity that needs to meet its own compliance obligation.

12 - Represents a Gas Toll expiring in July 2023. This resource qualifies as RA.

13 – 14 Represents imports of Firm Energy. Firm energy from an import is required to meet RA and once sold is not available to other parties for procurement. It is not clear from the material provided when these contracts expire.

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.	Rulemaking 21-10-002 (Filed October 7, 2021)

COMMENTS OF MARIN CLEAN ENERGY ON THE RESOURCE ADEQUACY IMPLEMENTATION TRACK 3 PROPOSALS & WORKSHOP

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DATE: February 24, 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.	Rulemaking 21-10-002 (Filed October 7, 2021)

COMMENTS OF MARIN CLEAN ENERGY
ON THE RESOURCE ADEQUACY IMPLEMENTATION
TRACK 3 PROPOSALS & WORKSHOP

Pursuant to the *Assigned Commissioner's Amended Scoping Memo and Ruling* issued in the above-captioned proceeding and Administrative Law Judge ("ALJ") Chiv's Email Ruling issued February 13, 2023 extending the period for parties to comment on the Implementation Track Phase 3 proposals and the February 8, 2023 Workshop, Marin Clean Energy ("MCE") hereby responds to proposals with additional near- and long-term refinements to consider relating to the California Public Utilities Commission's ("CPUC" or "Commission") Resource Adequacy ("RA") program.

I. Introduction

MCE shares the Commission's commitment to bolstering the RA program and supporting the efficient operation of a reliable and affordable grid. Recent environmental, market, and regulatory conditions have demonstrated, however, that the RA and Integrated Resource Planning ("IRP") programs have not efficiently achieved their primary objective to ensure resource sufficiency for grid reliability as evidenced by apparent shortages in the RA market and ad hoc procurement orders for new capacity, both of which are exacerbated by unprecedented amounts of new capacity being blocked by a large and growing interconnection queue. This inefficiency has become a significant driver of increased, and rapidly increasing, ratepayer costs that is proving unsustainable. The Commission must acknowledge and take steps to account for the increasing near-term RA supply scarcity that is excessively driving up prices and jeopardizing Load Serving Entities' ("LSE") ability to meet RA requirements despite diligent efforts to procure and develop new resources as quickly as possible. Regulatory requirements cannot be insulated from market realities and customer impacts that those regulatory requirements create. To protect ratepayers, requirements must be based on what is achievable and commercially reasonable. Otherwise, requirements can create extraordinary unintended consequences.

The regulatory expectation of purchasing RA at all costs on the one hand, and the threat of ballooning penalties on the other if requirements are not met, are harming ratepayers and not efficiently serving the shared goal of grid reliability. The current RA market is too constrained for this approach to be effective. Simply threatening LSEs with escalating penalties, particularly if those penalties are not calibrated to reflect the current heightened market, will do little to incentivize LSEs to procure, but instead result in more penalties and increased costs for ratepayers with minimal to no reliability benefit.

While reliability is imperative, the Commission must balance aggressive regulatory efforts to achieve reliability with the commercial realities that result from those aggressive efforts. The Commission must take policy approaches that mitigate upward pressure on prices that are not currently reflected in the Energy Division's RA proposals. Regulatory action cannot be limited to punitive action against LSEs' good faith procurement efforts to meet compliance requirements. To do so sends a powerful signal to sellers and undermines the limited negotiating power LSEs currently have given the extraordinarily tight RA market; a market situation exacerbated by the magnitude of the interconnection queue that is preventing resources from reaching the RA market to mitigate the RA supply shortage.

In these comments, MCE responds to the Energy Division proposals by proposing three short-term solutions to prioritize affordability and mitigate RA price increases while still strongly incentivizing LSEs to procure needed, and available, RA resources. MCE also proposes two structural ideas for the Commission to consider to restructure the RA market.

II. The Commission Should Adopt an RA Waiver Trigger Price as the Basis for an RA Waiver.

Given the current RA environment, Energy Division's purely punitive approach to RA non-compliance is ill-advised. Instead, consistent Public Utilities Code Section 380(b)(4), the Commission must consider ways to protect LSEs and consumers from excessive RA costs and unwarranted penalties. The Commission should provide additional oversight of the bilateral RA market and provide LSEs an opportunity to request a waiver from RA penalties for procurement deficiencies that are either the result of resources being unavailable or due to overtly commercially unreasonable prices for RA that far exceed the current penalty pricing structure.

The Commission could achieve this by adopting an RA waiver trigger price that would form the basis for an LSE's request to waive RA penalties.[1] An RA waiver trigger price would be a non-binding means for the Commission to signal to the market what it considers to be a reasonable price for LSEs to pay for RA in this current market; a price that is in the best interest of ratepayers while still incentivizing LSEs to procure aggressively and not default to simply paying a penalty price. MCE envisions that the RA waiver trigger price would identify a price for

[1] Should the Commission continue to oppose outright waivers for RA deficiencies, the Commission should at the very least adopt a process whereby LSEs can request a waiver from accruing deficiency points and penalty multipliers adopted in Decision ("D.") 21-06-029.

RA significantly above the current RA base penalty price that better reflects the state of the current market.

The trigger should properly incentivize resources to continue to sell into the California market. Importantly, this would not strictly limit the price for RA. The trigger would simply signal what the Commission, as regulator and administrator of the RA program, considers to be a reasonable RA price under the circumstances. For LSEs that have been unable to secure resources at prices above or below the trigger price, the Commission could implement a waiver process, similar to that used for Local RA, that provides deficient LSEs an opportunity to explain their procurement efforts and make a case for waiver of RA penalty assessments.

MCE's two primary guideposts in making this proposal are (a) properly incentivizing LSEs to procure available RA to meet reliability needs and (b) ratepayer affordability. As such, bidding at, above, or below the soft RA trigger price would not necessarily be dispositive of whether an LSE's penalty waiver is granted. However, it would be a basis for an LSE and the Commission to assess the reasonableness of an LSE's procurement choices and actions.

It is critical that LSEs still have a strong incentive to bid and pay reasonable market prices for RA, instead of defaulting to the penalty price for non-compliance. Adopting an RA trigger price as a benchmark to evaluate LSE's commercial activities and decisions would signal to LSEs and sellers that RA at any price is not a reasonable, nor viable solution for California. At the same time, it could incentivize LSEs to seek out all available RA at heightened, yet commercially reasonable prices, while signaling to the market that LSE's and their ratepayers can neither reasonably nor justly be expected to contract for RA at exorbitant prices that merely serve as a transfer of wealth from ratepayers to entities that hold RA.

Importantly, the RA penalty prices should not incentivize LSEs to defer their RA obligations in exchange for a penalty that is less than the market price for RA. On the other hand, penalties should not be used to penalize good actors. Again, MCE is concerned that Energy Division continuing to rely solely on penalties in the current tight market will simply lead to more instances of non-compliance, prejudice against LSEs that are willing to pay RA prices well above the current penalty prices, and incentivize LSEs to ultimately fall back on the penalty price as the economically justifiable solution, all of which will leave the state under-procured for RA. To do so would not serve California ratepayers or ensure reliability.

The Commission could consider a number of sources to inform a reasonable soft RA indicator. Some options to evaluate are (a) the cost of new entry, which is the current penalty price mechanism adopted for mid-term reliability ("MTR") deficiencies, (b) a penalty multiplier similar to what is currently implemented in the RA program; or (c) the CAISO Capacity Procurement Mechanism pricing. Regardless of the trigger price, the Commission must send a signal to LSEs and the market that exclusive reliance on penalties in a tight market is not acceptable, and neither is RA at any price. If penalties are not incentivizing LSEs to procure needed reliability resources, Section 380(b)(4) mandates the Commission promulgate RA program rules that "minimize enforcement requirements and costs", not exacerbate them.

III. The Commission Should Remove the Requirement for Non-Resource-Specific Imports to Self-Schedule or Bid Between $0/MWh and Negative $150/MWh.

Given the apparent in-state RA scarcity, the Commission must take steps to improve California LSEs' access to imports. In D.20-06-028, the Commission adopted a requirement for a non-resource-specific import to either self-schedule or bid into the California Independent System Operator ("CAISO") market at between $0/MWh and negative $150/MWh, which appears to be producing unintended consequences. MCE is concerned that this limitation has reduced, and will continue to reduce, California LSEs' ability to secure critical imports to serve California reliability needs. Under the current requirements, out of state RA resources are incentivized to sell to states other than California, contributing to limited California supply. Simply, requirements that limit the ability of import RA resources to recover their costs through the energy market by severely restricting importers' bidding flexibility have limited California LSEs' ability to contract with imports. As such, the Commission should modify the current import bidding restriction and allow non-resource-specific import resources to bid their costs based upon estimated fuel, variable operation and maintenance, and greenhouse gas costs. This enhancement to the import RA rules would better incentivize out-of-state RA resources to participate in the California market, provide reasonable assurance that physical supply is backing the RA commitment given the high likelihood their bid will clear, and address Energy Division's concerns that importers are bidding excessively high to prevent being called upon in the CAISO market.

IV. The Commission Should Conduct Market Monitoring of the Bilateral RA Market.

Given the bilateral structure of the RA market, there is limited visibility into LSE RA contract pricing. MCE acknowledges that this limited visibility for market participants serves an important market purpose and that full transparency of RA contract prices may in fact lead to price increases by setting a price floor for RA. MCE, however, urges the Commission to take a more active role to review LSEs' submitted RA contracts to better identify and evaluate instances of market power. MCE notes that coordination of this RA market monitoring function between the Commission and the CAISO may be needed to allow for the greatest insight. For example, the Commission could consider sharing information with the CAISO to assess any disconnect between the prices paid for RA and the operating costs and/or characteristics of the capacity resources. At this stage, MCE is only recommending transparency and not advocating for the Commission to implement any additional specific remedies to mitigate market power if enhanced monitoring finds evidence of such. MCE is simply suggesting that identifying and exposing potential inappropriate market power may reduce the tendency of sellers to ask for extraordinary price increases for capacity. MCE expects that market monitoring of RA contracts will send a message to both LSEs and sellers that despite the current scarcity in the RA market: (1) LSEs are not expected to pay excessive RA prices to enrich sellers and; (2) entities that hold RA are not sanctioned to demand exorbitant prices from LSEs in exchange for needed capacity.

V. The Commission Should Adhere to Orderly IRP Processes that Account for Actual Interconnection Capacity.

The state of the RA program emphasizes the importance of strong, long-term resource planning processes that ensure long-term resource needs are contemplated and resources are planned, brought online in an orderly fashion, and ultimately available to the RA program. An unprecedented amount of new capacity is expected to be procured and online by mid-/late-decade, and diligent and successful efforts are being made by Community Choice Aggregators, as demonstrated in the recent *Summary of Compliance with Integrated Resource Planning (IRP) Order D.19-11-016 and Progress Towards Mid-Term Reliability (MTR) D.21-06-026 Procurement* issued on February 13, 2023.

Regrettably, regulatory planning for this procurement need came too late and was done in an ad hoc manner that was divorced from the formal IRP planning process. It also failed to account for, or address the extraordinary CAISO interconnection queue backlog, which as of mid-2022 was 236 GW.[2] This so-called supercluster represents a massive amount of capacity potential that

[2] *See* CAISO Memorandum, *Briefing on Renewable and Energy Storage in the Generator Interconnection Queue*, July 21, 2022 (available here: http://www.caiso.com/Documents/BriefingonRenewables-RenewablesintheGeneratorInterconnectionQueue-Memo-Jul2022.pdf).

is prevented from making its way to the RA market and serving reliability. LSEs can make diligent efforts to respond to procurement orders, but an LSE's projects can only serve the RA program and reliability if those projects are able to get interconnected to the grid in a timely and efficient fashion. Adding more resources to the backlog is not increasing RA availability, but is increasing costs paid by ratepayers. As such, coordination between the IRP and the CAISO's interconnection processes is critical to both inform the magnitude of procurement orders and ensure that procurement can contribute to reliability.

Going forward, the Commission must follow its own ordered planning processes to ensure that procurement needs are (1) identified early; (2) those needs are based on empirical analysis; (3) procurement orders are calibrated to account for limitations such as interconnection backlogs and other regulatory frameworks that may frustrate LSE procurement efforts; and (4) LSEs and the market are given sufficient time to anticipate and respond to these needs. Ad hoc procurement orders backed by draconian penalties cause frenzy in the market, jeopardize the near-and mid-term reliability needs, and add to the affordability crisis in California.

VI. The Commission Should Consider the Feasibility of a Limited and Centralized RA Marketplace for Short-Term RA Transactions.

While diligent regulatory efforts are being made to reform the current RA program to better meet evolving reliability needs, the RA program may need additional fundamental restructuring. California needs to bring efficiency, transparency, and stability to transactions in the RA market, similar to the marketplace that operates under CAISO for energy. It would be beneficial to create some elements of an organized market for capacity where buyers and sellers of existing capacity can transact in an orderly and transparent manner. This would differ from capacity markets in other regions because it would not be needed or used to drive long-term capacity build or capacity auctions. Long-term capacity planning and buildout would be driven by the existing IRP process.

While MCE understands that establishing some elements of a capacity market in California is a complex effort, given the current state of the RA market and the critical need to ensure reliability and affordability, a capacity marketplace should not be disregarded. For example, the Commission, CAISO, and market participants could explore the creation of a market where buyers and sellers of capacity transact for short-term capacity needs,[3] but long-term capacity needs and new build capacity planning would still be driven, evaluated, and planned for exclusively through the IRP process as regulated by the Commission. In the long-run, such a market should allow for a more efficient and transparent transaction process for RA resources that: (a) avoids a multitude of bilateral transactions, (b) eliminates the risks of market power exertion, (c) identifies any scarcity, (d) provides certainty for investment to the sellers and availability to the LSEs at just prices, (e) integrates the availability of transmission into the process, and (f) allows the Commission to take a step back from administering short-term RA trading to focus on an orderly, well planned IRP process.

Again, though challenging and complex, MCE urges stakeholders and the Commission to consider all options to reform the chaotic bilateral RA market to enable the Commission to focus efforts on strong, stable, and long-term resource planning to ensure resources are efficiently procured and available to support reliability.

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[3] Short-term capacity procurement would be limited to 1-year forward commitments of existing resources.

VII. Conclusion

MCE commends the Commission and ALJ Chiv for the efforts to grapple with the current market and the rapidly evolving reliability needs of the state. MCE shares the Commission's concerns and goals on this front and looks forward to continuing to partner with the Commission to address reliability needs and advocate for the affordability of the regulatory decisions made.

Respectfully submitted,

/s/ Nathaniel Malcolm

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