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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	R.21-10-002

CALIFORNIA COMMUNITY CHOICE ASSOCIATION REPLY COMMENTS ON THE PROPOSED DECISION ON PHASE 1 OF THE IMPLEMENTATION TRACK: MODIFICATIONS TO THE CENTRAL PROCUREMENT ENTITY STRUCTURE

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March 7, 2022

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SUMMARY OF RECOMMENDATIONS

- The Commission should reject SCE's recommendation that CPEs have eight weeks from the date of final allocations to complete procurement;
- The PD must be modified to address inadequate incentives to self-show;
- The Commission should reject CEJA/UOCS's request to modify the PD such that justification statements would be publicly evaluated with an opportunity for public comment;
- The PD should be modified such that the same confidentiality provisions that apply to LSE procurement under D.06-06-066 also apply to CPE procurement; and
- The PD should be modified to require CPE procurement plans to go through the Procurement Review Group for procurement done outside the all-source solicitation.

I. INTRODUCTION

The California Community Choice Association (CalCCA)[1] submits these Reply Comments pursuant to Rule 14.3(d) of the California Public Utilities Commission (Commission) Rules of Practice and Procedure on the proposed *Decision on Phase 1 of the Implementation Track: Modifications to the Central Procurement Entity Structure* (PD) issued on February 10, 2022.

II. THE COMMISSION SHOULD REJECT SCE'S RECOMMENDATION THAT CPES HAVE EIGHT WEEKS FROM THE DATE OF FINAL ALLOCATIONS TO COMPLETE PROCUREMENT

The PD adopts a timeline that would give Central Procurement Entities (CPEs) until mid-August to make their local Resource Adequacy (RA) showings to the Commission. The timeline would then give load-serving entities (LSEs) from the end of August through the end of October to complete their procurement of system and flexible RA following allocation of credits from the CPE. Southern California Edison Company (SCE) recommends that the CPE have a full eight weeks from the date it receives final allocations to complete procurement and make showings to the Commission.[2]

The timeline in the PD and SCE's proposed modifications to the timeline should not be adopted. The PD significantly disadvantages LSEs procuring for their system and flexible obligations, especially considering that the three-year local RA program allows CPEs to largely know their local RA obligations three years forward. Because local requirements are known so far in advance, waiting until mid-August, two months prior to the year-ahead filings, to complete procurement is inadequate for LSEs with procurement obligations, and will result in higher customer costs.

As CalCCA proposed, the Commission must require CPEs to finalize their procurement for compliance year 2023 by June 2022 which will allow additional time for the CPE to fill the significant

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[1] California Community Choice Association represents the interests of 23 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, 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] *Southern California Edison Company's (U 338-E) Opening Comments on Proposed Decision on Phase 1 of the Implementation Track: Modifications to the Central Procurement Entity Structure*, Mar. 2, 2022 (R.21-10-002) (SCE Comments), at 2-3.

shortfall in CPE procurement for 2023.[3] After June 2022, if the 2023 local requirements changed with the June adoption, the CPE should be able to conduct procurement to fill the marginal need. If the CPE does not meet its full local RA obligation by the end of June 2022, when system and local requirements are finalized, the Commission should adopt a system and flexible RA waiver, or at minimum not assign any points, for the 2023 RA compliance year for any LSEs whose procurement deficiencies were impacted by CPE procurement shortfalls. Failure to mitigate LSE damages for shortfalls in the 2023 year will unduly increase customer costs without commensurate benefit, by forcing LSE customers to bear the costs of overprocurement or penalties. This is because the shortened compliance period and lack of certainty regarding CPE procurement amounts forces LSEs to choose between buying supply that may eventually be provided by the CPE (creating excess) or trusting that the CPE will meet its need and risking penalties if the CPE does not fill its entire position – a lose-lose proposition for customers in either case. Beginning for the compliance year 2024, the Commission must require CPE procurement to be completed in late September or early October one year prior to the yearly showings, as originally established in Decision (D.) 20-06-002, and any further procurement should only be for marginal needs resulting from changes between the three-year forward and one-year forward Local Capacity Requirements (LCRs).

III. THE PD MUST BE MODIFIED TO ADDRESS INADEQUATE INCENTIVES TO SELF-SHOW

The California Independent System Operator (CAISO), Pacific Gas and Electric Company (PG&E), and SCE all generally support the PD's modifications to the self-showing process, including the CPM cost allocation methodology that would allocate CPM costs to the self-showing LSE for CPMs resulting from non-performing self-shown resources not on planned outage or outside the CPE's Transmission Access Charge (TAC) area.[4] Parties in support of the proposed CPM cost allocation methodology fail to acknowledge the disincentives created by the PD that will likely discourage LSEs from self-showing local resources to the CPE.

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[3] *California Community Choice Association's Phase 1 Proposals in Response to the Assigned Commissioner's Scoping Memo and Ruling*, Dec. 13, 2021 (R.21-10-002) (CalCCA Proposals), at 8-9.

[4] *Opening Comments on Proposed Decision on Phase 1 of the Implementation Track: Modifications to the Central Procurement Entity Structure of the California Independent System Operator Corporation*, Mar. 2, 2022 (R.21-10-002), at 1-2; *Opening Comments of Pacific Gas and Electric Company (U 39 E) on Proposed Decision on Phase 1 of the Implementation Track: Modifications to the Central Procurement Entity Structure,* Mar. 2, 2022 (R.21-10-002), at 5-7; SCE Comments at 3.

Self-shown resources benefit all LSEs by reducing the overall local procurement obligation of a CPE. An LSE who self-shows a resource only receives a pro-rata reduction of CPE procurement costs provided by the resource. However, the PD would put the entirety of the backstop cost risk on the self-showing LSE. For example, an LSE with a three percent load ratio share that shows a 100 megawatts (MW) resource would receive a reduction in cost allocation from the CPE of three MWs. However, in exchange for this reduction in cost allocation, under the PD the self-showing LSE takes on 100 percent of the CAISO CPM cost risk if the resource is unable to perform in a given month. In addition to the proportional reduction in CPE procurement costs, self-showing LSEs only receive a potentially small payment through the Local Capacity Requirement Reduction Compensation Mechanism (LCR RCM) of $0/ kilowatt (kW) - month to at most $1.78/kW-month. Given the PD would put 100 percent of the CPM cost risk on self-showing LSEs if a self-shown resource is unavailable, LSEs do not receive adequate incentives to self-show.

Under the hybrid framework, LSEs are procuring to meet their own system and local obligations and may procure resources in local areas to meet these obligations. Despite holding these local resources, LSEs may choose not to self-show those resources to the CPE because of the disincentives established in the PD. Resources in a local area may be used to meet LSEs' system and flexible obligations can be substituted with a system resource if they are not self-shown. This is a significant disincentive to self-show because under the PD, self-showing would require LSEs to instead pay a premium cost for a local replacement resource or face CPM costs if they cannot find a replacement resource in the same local area.

To lessen these disincentives the PD must be modified to allow, but not require, self-showing LSEs to substitute for non-performing self-shown resources. If the self-showing LSE does not replace the self-shown resources, the CPE must be allowed to replace the resource and allocate costs to all LSEs. If neither the LSE nor CPE replaces the self-shown resource and backstop procurement is necessary, then backstop costs should be allocated to all LSEs, because all LSEs receive the local benefit of the resource that was self-shown.

IV. THE COMMISSION SHOULD REJECT CEJA/UOCS'S REQUEST TO MODIFY THE PD SUCH THAT JUSTIFICATION WOULD BE PUBLICLY EVALUATED WITH AN OPPORTUNITY FOR PUBLIC COMMENT

The California Environmental Justice Alliance (CEJA) and Union of Concerned Scientists (UOCS) recommended the PD be revised to include a public evaluation of justifications statements submitted by LSEs who elect not to self-show resources.[5] The Commission should not adopt this proposal. The PD correctly states the justification statement should be submitted with the year-ahead RA filing, which is only accessible by the Commission, and notes the purpose of the proposed justification is to improve the CPE framework and inform any necessary adjustments, and that it is not to be used as an enforcement mechanism. The justification statements should be used exclusively as an opportunity for the Commission to understand why LSEs choose not to self-show resources, as justifications may contain confidential market-sensitive information and business strategy. The Commission itself should evaluate justifications statements to analyze if changes are needed to the CPE framework in the future. Within that process, the Commission may find it beneficial to provide summary-level information on the types of justifications provided to inform parties; based on this summary, parties can then make their own recommendations on any further changes necessary to the RA CPE program. It is not necessary for justification statements to be filed in a public document within the proceeding or have parties comment on each justification statement.

V. THE PD SHOULD BE MODIFIED SUCH THAT THE SAME CONFIDENTIALITY PROVISIONS THAT APPLY TO LSE PROCUREMENT UNDER D.06-06-066 ALSO APPLY TO CPE PROCUREMENT

In its opening comments, Shell Energy North America (Shell) recommends the Commission modify the PD to ensure confidentiality rules applicable to the CPE's procurement information not restrict public access any more than the confidentiality rules that apply to LSEs' RA procurement under D.06-06-066.[6] The Commission should adopt this recommendation and clarify confidentiality provisions adopted in D.06-06-066 apply to both LSEs and CPEs. Protecting market-sensitive information related to both CPE and LSE procurement is important in ensuring information is not disclosed that would negatively impact market prices or ratepayer costs. D.06-06-066 appropriately addresses this objective. There is no justification for the Commission to provide CPEs more confidentiality protection than LSEs. For these reasons, the Commission should adopt Shell's modifications to the PD and clarify the confidentiality provisions adopted in D.06-06-066 also apply to the CPEs.

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5 *California Environmental Justice Alliance and Union of Concerned Scientists Comments on the Proposed Decision on Modifications to the Central Procurement Entity Structure*, Mar. 2, 2022 (R.21-10-002), at 1-2.

6 *Opening Comments of Shell Energy North America (UC), L.P. d/b/a Shell Energy Solutions on the Presiding Judge's February 10, 2022 Proposed Decision Addressing Protocols for the Central Procurement Entity*, Mar. 2, 2022 (R.21-10-002), at 3.

VI. THE PD SHOULD BE MODIFIED TO REQUIRE CPE PROCUREMENT PLANS TO GO THROUGH THE PROCUREMENT REVIEW GROUP FOR PROCUREMENT DONE OUTSIDE THE ALL-SOURCE SOLICITATION

SCE recommends modification of Ordering Paragraph (OP) 11, which states that contracts with a five-year term or less shall be deemed reasonable and preapproved if the Cost Allocation Mechanism (CAM) Procurement Review Group (PRG) was properly consulted, as described in OP 13 of D.20-06-002.[7] SCE recommends the Commission clarify the PD such that broker contracts with a term of five years or less do not require consultation with CAM PRG prior to the CPE executing the contract, provided the CPE followed all of the other selection requirements proposed in the PD's OP 11. SCE proposes to notify the CAM PRG as soon as practicable after the execution of such broker transactions, with information evidencing that the other requirements were met.[8]

CalCCA agrees with SCE that there may not be time prior to executing a broker or bi-lateral contract to consult with the PRG when the time between contract negotiation and execution is very compressed and supports its proposal to notify the CAM PRG as soon as practical after contract execution. However, the Commission should also require the CPE to consult with the PRG on its plan for conducting procurement outside the all-source solicitation, including the opportunities it plans to pursue and the criteria with which it plans to evaluate offers. Taken together, this process would ensure that before conducting bi-lateral procurement, the CAM PRG is consulted and afforded the opportunity to provide advice regarding the CPE's plan and after conducting bi-lateral procurement, the CAM PRG is able to evaluate if the CPE's actual procurement was consistent with the plan.

VII. CONCLUSION

CalCCA appreciates the opportunity to submit these Reply Comments and requests adoption of the recommendations proposed herein.

Respectfully submitted,

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March 7, 2022

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[7] PD OP 11.
[8] SCE Comments at 5.

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

Order Instituting Rulemaking to Revise General Order 156 to Include Certain Electric Service Providers and Community Choice Aggregators and Encourage Voluntary Participation by Other Non-Utility Entities Pursuant to Senate Bill 255; Consider LGBT Business Enterprise Voluntary Target Procurement Percentage Goals; Incorporate Disabled Business Enterprises; Modify the Required Reports and Audits; and Update Other Related Matters.	R.21-03-010

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON THE PROPOSED DECISION

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BEFORE THE PUBLIC UTILITIES COMMISSION
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Order Instituting Rulemaking to Revise General Order 156 to Include Certain Electric Service Providers and Community Choice Aggregators and Encourage Voluntary Participation by Other Non-Utility Entities Pursuant to Senate Bill 255; Consider LGBT Business Enterprise Voluntary Target Procurement Percentage Goals; Incorporate Disabled Business Enterprises; Modify the Required Reports and Audits; and Update Other Related Matters.	R.21-03-010

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
REPLY COMMENTS ON THE PROPOSED DECISION

The California Community Choice Association (CalCCA)[1] submits these Reply Comments pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure on the proposed *Decision Revising General Order 156 Supplier Diversity Program To Implement Senate Bill 255, Adopt A Voluntary Procurement Goal For LGBT Business Enterprises, Incorporate Persons With Disabilities Business Enterprises, And Other Updates* (PD or Proposed Decision), issued on February 9, 2022.

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[1] California Community Choice Association represents the interests of 23 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, 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.

I. INTRODUCTION

CalCCA does not change its position on any of the topics that it raised in Opening Comments but rather uses this opportunity to respond specifically to the Opening Comments of Shell Energy North America (US), L.P. d/b/a Shell Energy Solutions and the Alliance for Retail Energy Markets (Shell/AReM).[2] CalCCA responds to Shell/AReM's assertion that the application of unique reporting requirements applicable to community choice aggregators (CCAs) is unreasonable, discriminatory, and unfair. As set forth below, the different statutory reporting requirements applicable to CCAs compared with those of investor-owned utilities (IOUs) and Electric Service Providers (ESPs) is intentional and necessary given the unique restrictions on CCAs (not applicable to IOUs and ESPs) from Article 1, Section 31(a) of the California Constitution (known as Proposition 209).

II. SHELL/AREM'S STATEMENT THAT THE PD'S APPLICATION OF DIFFERENT REPORTING REQUIREMENTS TO CCAS VERSUS ESPS IS UNREASONABLE AND DISCRIMINATORY IGNORES THE UNIQUE STATUTORY REQUIREMENTS APPLICABLE TO CCAS

Shell/AReM assert that ESPs should have the same reporting requirements as CCAs and that the PD's failure to do so "is unreasonable, unduly discriminatory, and inconsistent with [Public Utilities] Code Section 453(a)."[3] Shell/AReM further state that differing reporting requirements for CCAs and ESPs subject large ESPs to "unfair competition," inconsistent with Business and Professions Code Section 17200.[4] Shell/AReM's arguments regarding the Commission's unique reporting requirements for CCAs being unreasonable, unduly discriminatory, or rising to the level of unfair competition ignores the unique statutory

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2 *Opening Comments of Shell Energy North Amercia (US), L.P. d/b/a Shell Energy Solutions and the Alliance for Retail Energy Markets on Assigned Commission Rechtschaffen's February 9, 2022 Proposed Decision,* R.21-03-010 (Mar. 1, 2002) (Shell/AReM Opening Comments).

3 *Id.* at 3, 5-7.

4 *Id.* at 3, 7.

framework applicable to CCAs, and not ESPs or IOUs, in Public Utilities Code Section 366.2(m).

Senate Bill (SB) 255 added CCAs and ESPs as entities subject to the Commission's Supplier Diversity program (which for the electric sector previously only applied to IOUs), but clearly distinguished the unique statutory requirements for CCAs (Section 366.2(m)) versus ESPs (Sections 8281-8286).[5] As detailed in CalCCA's Opening Comments, the Legislature's application of different statutory requirements for CCAs in Section 366.2(m) was intentional. CCAs, but not ESPs or IOUs, are prohibited from granting preferential treatment to suppliers based on their "race, sex, color, ethnicity, or national origin" by Article 1, Section 31(a) of the California Constitution (known as Proposition 209) and accordingly different requirements must apply.[6]

Shell/AReM's contention that adopting different reporting requirements for CCAs is unreasonable or unduly discriminatory under Public Utilities Code section 453(a) ignores the express language of that statute. Section 453(a) has no bearing on adoption by the Commission or Legislature of different requirements for differently situated load-serving entities (LSEs). Instead, it prohibits a "public utility" from "mak[ing] or grant[ing] any preference or advantage to any corporation or person or subject any corporation or person to any prejudice or disadvantage." Moreover, even if the subject and purpose of this statute were relevant, the language still could not be applied to this situation. Section 453(a) prevents discrimination by

[5] SB 255 (2019) (amending Public Utilities Code section 366.2 (regarding CCAs) and 8283 (adding ESPs to the list of entities subject to sections 8281-8286)).

[6] CalCCA Opening Comments at 3-10.

"public utilities," and CCAs are not "public utilities" as defined by Public Utilities Code Section 216(a)(1).[7]

Furthermore, Shell/AReM err in asserting that the PD's proposed treatment of ESPs differently than CCAs subjects ESPs to "unfair competition" under Business and Professions Code Section 17200. The Business and Professions Code allows for injunctive relief against "any person who engages, has engaged, or proposes to engage in unfair competition…."[8] Shell/AReM fail to substantiate how the Proposed Decision's differential treatment of ESPs and CCAs with respect to reporting requirements (based on legislative mandate) would create unfair competition under the Business and Professions Code. For the reasons set forth above, CalCCA requests that the Commission distinguish the reporting requirements of CCAs from both ESPs and IOUs given the statutory requirements uniquely applicable to CCAs in Section 366.2(m) (as opposed to the requirements imposed on ESPs and IOUs in Section 8281-8286).

III. CONCLUSION

CalCCA appreciates the opportunity to submit these Reply Comments and requests adoption of the recommendations proposed herein.

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March 7, 2022

7 *See* Pub. Util. Code § 216(a)(1) ("public utility" includes every common carrier, toll bridge corporation, pipeline corporation, gas corporation, electrical corporation, telephone corporation, telegraph corporation, water corporation, sewer system corporation, and heat corporation, where the service is performed for, or the commodity is delivered to, the public or any portion thereof.")

8 Bus. and Prof. Code § 17203.

California Community Choice Association

SUBMITTED 03/14/2022, 12:19 PM

Contact

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1. Comment on chapter 1 Introduction:

CalCCA has no comments at this time.

2. Comment on chapter 2 Reliability Assessment:

CalCCA has no comments at this time.

3. Comment on chapter 3 Policy-Driven RPS Transmission Plan Analysis:

Consideration of Long-Lead-Time Resources

The California Community Choice Association (CalCCA) is encouraged to see the 440 megawatts (MW) of geothermal in southern Nevada included in the Preferred System Plan (PSP) busbar mapping and the California Independent System Operator's (CAISO's) draft study plan. Significant additional potential for long lead time resources in the state of Nevada exists beyond what was included in the PSP, however. Such resources should be included in this cycle of the Transmission Planning Process (TPP) to allow for the development of significant amounts of cost-effective resources in line with the California Public Utilities Commission's (CPUC's) procurement requirements and to avoid stranded resource investments.

Within the Integrated Resource Plan (IRP) proceeding, CalCCA asked that the CPUC update the PSP Core Portfolio to plan for at least 2,000 MW of further incremental renewable resources imported from Nevada to allow the CAISO to study necessary import expansion in that region. The CPUC's Preferred System Plan Decision (D.22-02-004) stated that this request can be addressed in the next TPP portfolio.[1] It is critical for the CAISO to conduct this study in this TPP cycle as a sensitivity to reflect the availability and location of cost-effective resources (*i.e.*, "long-lead-time resources" that can fulfill the CPUC's Mid-term Reliability (MTR) requirements). Failure to do so could impact the ability for load-serving entities (LSEs) with out-of-state (OOS) RA contracts to receive Maxim Import Capability (MIC) in those areas because a study is needed for the CAISO to approve policy-driven projects associated with a MIC expansion request.

CalCCA also encourages the CAISO to complete a more comprehensive analysis of the location of expected near-term geothermal resources in Nevada as part of the TPP. The busbar mapping in the PSP Core Portfolio places 440 MW of geothermal resources at the Beatty substation in southern Nevada. However, CCAs are observing that many geothermal resources available in the near-term are located in northern or western Nevada and not easily delivered at the Beatty substation or other southern Nevada transmission paths. Rather, they are relying on paths like Summit or Gonder IPP which have limited headroom for imports to CAISO. The TPP should evaluate cost-effective solutions for enabling transmission for these resources to the CAISO — some of which may reach commercial operations date (COD) as early as 2024. Long-term, the TPP should also evaluate how projects like Greenlink Nevada, the TransCanyon Cross-tie, and GridLiance West projects may improve the accessibility of geothermal power in Nevada.

Market Outreach on OOS Resource Potential

In the 2021-2022 TPP cycle, the CAISO indicated it plans to conduct market outreach regarding market interest in OOS resources, specifically OOS wind in Idaho. The CAISO should broaden this outreach to gauge market interest for other OOS resources to inform transmission needed to deliver projects LSEs are pursuing.

Maximum Import Capability Improvements

LSEs are increasingly finding opportunities to contract with resources outside of the CAISO Balancing Authority Area (BAA) in order to meet state climate objectives and procurement mandates. Given a significant risk in contracting with OOS resources is the ability to obtain MIC, the CAISO should provide additional transparency on how transmission upgrades identified in the TPP will affect MIC needed for LSEs to show resources out of state as resource adequacy (RA). Because LSEs must secure MIC at the right nodes to be able to use out-of-state resources like Nevada geothermal to provide RA capacity, they must be able to understand how projects in the transmission plan will affect import capability at specific nodes. The CAISO should provide data on deliverability or other technical limitations that would limit the ability for the CAISO to approve MIC expansions at specific branches. This transparency will minimize the risk of planned projects failing to materialize and minimize costs associated with the uncertainty around available MIC.

[1] *Decision Adopting 2021 Preferred System Plan* (R.20-05-003), Feb. 10, 2022, at 173.

4. Comment on chapter 4 Economic Planning Study:

CalCCA has no comments at this time.

5. Comment on chapter 5 Interregional Transmission Coordination:

CalCCA has no comments at this time.

6. Comment on chapter 6 Other Studies:

CalCCA has no comments at this time.

7. Please provide any additional comments:

CalCCA has no comments at this time.

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 THE LOCAL CAPACITY REQUIREMENT (LCR) FINAL WORKING GROUP REPORT AND ENERGY DIVISION'S LOSS OF LOAD EXPECTATION STUDY

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SUMMARY OF RECOMMENDATIONS

Recommendations on Energy Division's Loss of Load Expectation and Effective Load Carrying Capability Study Results for 2024:

- The Commission should clarify how it uses or intends to use ELCC values for storage and hybrid resources;
- Other than updating the ELCC values for wind to account for the adoption of regional ELCC calculations in 2023 in D.21-06-029, the Commission should not adopt new ELCCs for wind and solar until a slice-of-day framework is adopted;
- Energy Division's import assumptions are too conservative and do not match the CAISO's PLEXOS assumptions, nor the data on actual imports. Energy Division staff should work with CAISO to determine reasonable import levels, and both the Commission and the CAISO should use the same assumptions;
- A new LOLE study is necessary once a slice-of-day framework is adopted to assess how the PRM is applied under a slice-of-day framework and to account for changes in inputs due to resource counting;
- The model should assume planned outages are optimized such that generators are available during constrained system conditions;
- Removing or altering deliverability restrictions in the NQC may be appropriate under a slice-of-day framework and should be considered in the Reform Track;
- Staff should perform LOLE studies on a regular cadence as inputs to the study such as load forecast, resource mix, and counting rules evolve. Updates to the PRM and ELCCs should only be made following an LOLE study if there are significant changes to the results and with enough time for parties to vet the results and for LSEs to plan and conduct orderly procurement to meet the new PRM;
- Storage and hybrid resources should not be valued using an ELCC. They should continue to be valued as they are today pending the outcome of the Reform Track;
- CalCCA generally supports the UCAP concept so long as UCAP is accurately reflected in the PRM;
- If UCAP is adopted, ambient derates should be included in the UCAP rather than the PRM; and
- The IEPR load forecast should be used to calculate the PRM, consistent with what is used to establish LSE RA requirements.

SUMMARY OF RECOMMENDATIONS continued

Recommendations on the California Community Choice Association and Pacific Gas and Electric Company's (U 39 E) Local Capacity Requirement (LCR) Final Working Group Report:

- Coordinated efforts between the IRP and TPP are required to ensure the state can meet its LCRs in a cost-effective manner with carbon-free resources; and

- CalCCA supports noticing the service list of key LCR study process milestones to allow for more meaningful input to the study results.

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CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE LOCAL CAPACITY REQUIREMENT (LCR) FINAL WORKING GROUP REPORT AND ENERGY DIVISION'S LOSS OF LOAD EXPECTATION STUDY

The California Community Choice Association (CalCCA)[1] submits these Comments pursuant to the schedule set forth in the *Administrative Law Judge's Ruling Seeking Comments on the Future of Resource Adequacy Working Group Report and the Local Capacity Requirement Working Group Report* (Ruling)*,* issued on March 4, 2022.

I. INTRODUCTION

CalCCA appreciates the opportunity to comment on both Energy Division's Loss of Load Expectation and Effective Load Carrying Capability Study Results for 2024[2] (LOLE Study) and the California Community Choice Association and Pacific Gas and Electric Company's (U 39 E) Local Capacity Requirement (LCR) Final Working Group Report[3] (Final Report). Both

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1 California Community Choice Association represents the interests of 23 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, 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, Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

2 *Energy Division Study for Proceeding R.21-10-002, Loss of Load Expectation and Effective Load Carrying Capability Study Results for 2024* (Rulemaking (R.) 21-10-002), Feb. 18, 2022.

3 *California Community Choice Association and Pacific Gas and Electric Company's (U 39 E) Local Capacity Requirement (LCR) Final Working Group Report* (R.21-10-002), Feb 28, 2022.

documents demonstrate the considerable effort put forth by Energy Division staff and working group participants to ensure the Resource Adequacy (RA) program effectively evolves to meet future grid reliability needs.

Adequate planning and modeling are critical to ensure the RA program provides a stable procurement environment and reliable electric service. CalCCA applauds the California Public Utilities Commission (Commission) for its efforts in performing robust modeling and analysis in the LOLE Study to inform the planning reserve margin (PRM) and effective load carrying capability (ELCC) values. CalCCA generally supports the modeling assumptions, with the exception of the import assumptions and appreciates staff's questions regarding how LOLE analysis fits into the work underway in the RA Reform Track around slice-of-day frameworks. The comments in section II below respond to the questions posed by staff at the end of the LOLE Study.[4] In summary, CalCCA recommends:

- The Commission should clarify how it uses or intends to use ELCC values for storage and hybrid resources;
- Other than updating the ELCC values for wind to account for the adoption of regional ELCC calculations in 2023 in Decision (D.) 21-06-029, the Commission should not adopt new ELCCs for wind and solar until a slice-of-day framework is adopted;
- Energy Division's import assumptions are too conservative and do not match the California Independent System Operator Corporation's (CAISO's) PLEXOS assumptions, nor the data on actual imports. Energy Division staff should work with CAISO to determine reasonable import levels, and both the Commission and the CAISO should use the same assumptions;
- A new LOLE study is necessary once a slice-of-day framework is adopted to assess how the PRM is applied under a slice-of-day framework and to account for changes in inputs due to resource counting;
- The model should assume planned outages are optimized such that generators are available during constrained system conditions;

[4] LOLE Study, Appendix A, at 28.

- Removing or altering deliverability restrictions in the Net Qualifying Capacity (NQC) may be appropriate under a slice-of-day framework and should be considered in the Reform Track;

- Staff should perform LOLE studies on a regular cadence as inputs to the study such as load forecast, resource mix, and counting rules evolve. Updates to the PRM and ELCCs should only be made following an LOLE study if there are significant changes to the results and with enough time for parties to vet the results and for LSEs to plan and conduct orderly procurement to meet the new PRM;

- Storage and hybrid resources should not be valued using an ELCC. They should continue to be valued as they are today pending the outcome of the Reform Track;

- CalCCA generally supports the unforced capacity (UCAP) concept so long as UCAP is accurately reflected in the PRM;

- If UCAP is adopted, ambient derates should be included in the UCAP rather than the PRM; and

- The Integrated Energy Policy Report (IEPR) load forecast should be used to calculate the PRM, consistent with what is used to establish load-serving entity (LSE) RA requirements.

Also critical to the success of the RA program is the Local Capacity Requirement (LCR) study process. As the state undergoes the transition to 100 percent clean energy, particular attention will need to be paid to local areas to ensure the LCRs can be met with clean resources or reduced through transmission upgrades. Processes at the Commission and the CAISO must align to ensure a cost-effective and reliable transition away from reliance on fossil fuel resources in local capacity areas. In comments to the Final Report, CalCCA offers the following recommendations:

- Coordinated efforts between the IRP and TPP are required to ensure the state can meet its LCRs in a cost-effective manner with carbon-free resources; and

- CalCCA supports noticing the service list of key LCR study process milestones to allow for more meaningful input to the study results.

II. COMMENTS TO ENERGY DIVISION'S LOLE STUDY

The following provides CalCCA's responses to the eleven questions posed by staff at the end of the LOLE Study.

1. Which portfolio scenario (Base, A, B, C or D) best represents the likely portfolio in 2024? Which set of technology ELCC values should be assumed in selecting the short-term average ELCC values?

CalCCA generally supports using the base portfolio to represent the likely portfolio in 2024 and to select the short-term average ELCCs. The proposed base portfolio uses existing resources, resources identified in LSE IRP Plans, and additional storage capacity selected in Renewable Energy Solutions Model (RESOLVE) to calculate technology specific ELCCs. This portfolio represents the significant new resource build expected to take place between now and 2024. LSE IRP Plans, while potentially not an exact predictor of the resources that will be available in 2024, provide a reasonable representation of what can be expected to be developed in future years.

The Commission should provide clarity, however regarding, a) how it intends to use the analysis for changes to ELCCs for 2023 – other than updating the ELCC values for wind to account for the adoption of regional ELCC calculations in 2023 in D.21-06-029,[5] the Commission should not adopt the study results to make any changes to ELCCs in 2023 as any changes to ELCCs in 2023 will have to be reconsidered for 2024 after a slice-of-day framework is implemented, unnecessarily complicating LSE contracting and planning; and b) how it has or intends to use the results of the storage and hybrid ELCCs since they are not currently used to establish the NQC of these resources. In addition to clarifications around the ELCC methodology

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[5] *Decision Adopting Local Capacity Obligations for 2022-2024, Flexible Capacity Obligations for 2022, and Refinements to the Resource Adequacy Program* (R.19-11-009), June 24, 2021 (D.21-06-029), Ordering Paragraph 15.

for hybrid resources posed in question 8 below, clarification is needed around how ELCCs for storage and hybrids impact the ELCC value of other technologies and how they impact the PRM calculation. Do the ELCCs for storage and hybrids contribute to the diversity effects of solar and wind ELCCs? How do the ELCCs for storage and hybrids impact the PRM? Answers to these questions are needed to help parties better interpret the ELCC values and their use. The Commission should allow an additional opportunity for party comment following these clarifications.

2. What, if any changes should be made to the assumptions used to perform the LOLE study?

Changes should be made to the import assumptions used in the LOLE study. Energy Division's import assumptions, which limits imports to 4,000 megawatts (MW) during peak hours, are too conservative and should be revised to be more consistent with actual historical levels of imports. In revising the import assumptions, the Commission should clarify the reasoning behind the import assumptions used in the study, and work with CAISO to determine reasonable import levels so that both the Commission and the CAISO use the same assumptions. The Commission's modeling uses "a 4,000 megawatt (MW) peak import constraint in Hour Ending (HE) 17-22 [*i.e.*, 5 PM to 10 PM] in all 12 months of the year."[6] During the workshop, staff verbally clarified that this value was based on a review of firm RA import contracts.[7] However, this import constraint is implemented differently than that used by the CAISO in their PLEXOS model publicly posted in February 2022.[8] The table below outlines the differences between the two models.

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6 LOLE Study at 9.

7 LOLE Study. Presentation in Resource Adequacy (R.21-10-002), Mar. 3, 2022 (Presentation).

8 CAISO Integrated Resource Planning 38MMT Core Portfolio PLEXOS models, located at http://www.caiso.com/market/Pages/ReportsBulletins/Default.aspx under "Special Reports: Integrated Resource Planning Preferred System Planning Model."

Table 1: Import Assumptions Comparison

Item	CAISO PLEXOS model	CPUC RA LOLE model	Do the models match?
Total simultaneous import limit (GW)	5.5 GW	4 GW	No
Hours of year in which constraint applies	HE 17-22	HE 17-22	Yes
Months of year in which constraint applies	June - September	All 12 months of year	No
Items falling under import constraints	Unspecified imports from all non-CAISO regions into CAISO Carbon-free imports into CAISO including Pacific NW Hydro, Hoover, and Palo Verde Directly imported RPS resources from other balancing authorities	Unclear	Unclear
Years Studied	2026, 2030	2024	N/A (models are for different purposes)

Further, the import constraint used in the LOLE study is likely too low to reflect actual imports into the CAISO. Table 2 below shows the average level of imports from other balancing authorities into CAISO, in MW at 5-minute intervals, from June – September HE 17-22 in calendar year 2021.[9] Average import flows into California are significantly higher than 4,000 MW in virtually all hours the Commission is proposing to limit imports.

Table 2: Average Import Levels by Hour and Month

Row Labels	6	7	8	9
17	2,257	3,078	4,434	5,107
18	2,994	3,668	5,038	6,336
19	4,464	4,815	6,287	7,817
20	6,300	6,069	7,326	8,510
21	7,271	6,619	7,959	8,667
22	7,571	7,156	8,211	8,609

9 Data from http://www.caiso.com/Documents/ProductionAndCurtailmentsData_2021.xlsx.

Even assuming minimum levels of import flows into CAISO, in MW at 5-minute intervals during the same period, there are hours in September where the minimum amount of imports is higher than 4,000 MW, implying that 4,000 MW is not a realistic limit.

Table 3: 2021 Minimum Import Levels by Hour and Month

Row Labels	6	7	8	9
17	-412	-1,488	-878	2,029
18	218	-1,454	-672	3,008
19	432	-198	147	4,461
20	1,283	913	1,061	5,438
21	2,727	1,719	3,086	5,617
22	3,233	2,033	3,871	6,101

Given these differences, the Commission should do the following. First, the Commission must clarify the reasons for the discrepancies between the CAISO's PLEXOS model import assumptions and the Commission's RA LOLE model import assumptions. These discrepancies are marked "No" or "Unclear" in the last column of Table 1 above, and include the total simultaneous import limit, the months of the year when it applies, and which out-of-CAISO generators fall under the import constraint. Second, the Commission should also clarify why it chose to use the import limit from HE 17 to HE 22 (5 PM to 10 PM). This period does not match the period studied in the California Energy Commission's (CEC's) stack analysis,[10] which analyzes 3 PM to 9 PM, nor does it match when the Commission requires imports to bid below $0 to receive RA credit, which is 4 PM to 9 PM.[11] Third, the Commission must reconsider the 4,000 MW simultaneous import limit, which is likely too low to reflect real-world conditions. Instead, the Commission should work with CAISO to determine a more reasonable import levels, and both the Commission and the CAISO should use the same assumption.

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[10] *Staff Paper - Updated 2022 Summer Supply Stack Analysis* (21-ESR-01), at 11-13. Located at: https://efiling.energy.ca.gov/GetDocument.aspx?tn=241145&DocumentContentId=74989

[11] *Decision Adopting Resource Adequacy Import Requirements* (R.17-09-020), June 25, 2020 (D.20-06-028), Ordering Paragraph 2.

To provide these necessary clarifications, Energy Division should publish additional information around how it has implemented its import assumptions. The raw PLEXOS table from the CAISO's modeling is included in Appendix A. This table shows how the simultaneous import constraint is implemented in PLEXOS, which resources fall under the constraint, and which months it applies in. The Commission could provide a similar table to allow parties to fully assess the import assumptions made.

The Commission should also provide transparency around how each assumption made in the LOLE study drives changes in the PRM from month to month. The application of assumptions can have a significant impact on resulting PRMs. Given the relatively large differences between the monthly PRMs, the Commission should provide transparency around which assumptions drive these differences and why.

3. Is a LOLE study appropriate to calculate RA obligations for: 1.) a peak RA capacity framework, 2.) a slice of day reliability construct?

Yes, an LOLE study is appropriate to calculate RA obligations for both a peak capacity framework and a slice of day reliability construct. In fact, a new LOLE study is critical once the final slice of day construct is adopted because the adopted construct will likely impact how PRM is determined and what the appropriate level of PRM is. For example, resource counting rules could impact the level of PRM required to achieve a targeted level of reliability. The 24-hour slice-of-day proposal would alter the qualifying capacity (QC) methodology for wind and solar; rather than rely on an ELCC methodology to account for these resources, their contributions to meet load would be determined on an hourly basis based on historical profiles. Should the 24-hour slice-of-day proposal be adopted, the Commission should re-run the LOLE study using wind and solar profiles which more closely represent the expected values used for the resources in the RA counting rules. Failure to do so could result in double counting of the renewable variance toward the PRM. These changes will impute a potentially different level of uncertainty within the RA construct and as such, the PRM must be revisited in the context of the slice-of-day framework.

4. How should planned outages be treated in calculating an RA PRM using an LOLE study?

When calculating an RA PRM, planned outages should be optimized to maximize resource availability during constrained hours and minimize their impact on the PRM. The LOLE Study indicates that Strategic Energy Risk Valuation Model (SERVM) models planned maintenance given an annual amount of required maintenance based on Generator Availability Data Set (GADS) outage data and allocates required planned maintenance across the months according to monthly system conditions.[12] Unlike forced outages, planned outages can be timed by the generator and must be approved by the CAISO such that maintenance occurs at the most opportune time for system conditions in order to optimize energy revenues for the generator and minimize expected disruption to the grid. Therefore, as indicated in the LOLE Study, planned outages generally occur when supply conditions are not tight.[13] It is reasonable to assume maintenance is taken during times of the year when energy prices are expected to be low, such that generators can be available to take advantage of high market prices when the system is constrained. Similarly, the CAISO has the ability to disallow a planned outage if anticipated grid conditions would make such an outage risk grid reliability or if an RA resource requesting a planned outage does not provide a substitute resource. The modeling should reflect these practices such that planned outages are optimized to reduce their impact on the PRM and that generators are not taking maintenance when the system is constrained.

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[12] LOLE Study at 9.
[13] *Id.* at 19.

5. Would removing deliverability restrictions in the NQC calculation be an accurate translation of the way that resources provide reliability value to CAISO in most instances, outside of particularly constrained times? Would it be possible that certain resources would avoid making transmission upgrades because they have less of an incentive? Do parties have any other arguments pro or con about deliverability restrictions in the QC calculation?

Modifications to deliverability restrictions in the NQC calculation should be considered in the Reform Track, in conjunction with the slice-of-day proposals. Removing or altering deliverability restrictions to the NQC could be appropriate under a slice of day construct, under which resources have NQCs during individual slices. The current deliverability study methodology ensures that RA capacity can provide energy to the system when dispatched during peak load hours without being restricted by the dispatch of other resources at the same time. This method is not appropriate for all slices, particularly slices during off-peak hours. Considerations of how to modify deliverability restrictions on NQC should be considered in the Reform Track, where slice-of-day proposals are being considered, to ensure resources are not over or under counted under a new slice-of-day framework.

6. How often should staff perform LOLE studies for RA obligations and ELCC values? Are there problems with performing RA studies and ELCC studies together simultaneously as is done in this proposal?

LOLE studies should be updated regularly to reflect changes to study inputs (*i.e.*, load forecast changes, resource retirements, or counting rule changes). Updates to the PRM and ELCCs should only be made following an LOLE study if there are significant changes to the results and with enough time for parties to vet the results and for LSEs to plan and conduct orderly procurement to meet the new PRM. This will provide needed certainty to LSEs in their planning and procurement. Over the next several years, these inputs are expected to change frequently due to procurement orders and new resource build, increased electrification, and planned structural RA reform. The Commission should therefore adopt a timeline for regularly conducting an LOLE study that allows sufficient time to perform the analysis and conduct a robust vetting process while accounting for these changes in a timely manner. This process should be aligned with the IRP process such that inputs derived from the IRP process are incorporated into the evaluation of RA requirements in a timely manner.

If an LOLE study can be easily performed and vetted on an annual basis timely and cost-effectively, the Commission should perform the LOLE study annually to inform the PRM and make changes if necessary. This annual update should be performed for at least the next few years to gain a better understanding of the level of change to the PRM that could be expected from a given level of inputs. If performing an annual LOLE analysis will be overly burdensome the Commission could either determine a more feasible amount of time to regularly review the PRM (*e.g.*, every two years or on the same cadence as IRP cycles). Alternatively, if inputs remain relatively stable year over year, the Commission could establish a threshold that would trigger a new LOLE study based on changes in inputs. These alternatives will ensure the PRM remains up to date in the event an annual PRM review process is not feasible.

7. Do parties have comments on the revised ELCC methodology which assigns diversity benefits via a series of marginal ELCC studies at different portfolio penetration points? Or do parties prefer the older method of calculating a capacity weighted average method of assigning diversity benefit?

CalCCA has no comments at this time.

8. Should storage and hybrid resources be valued using an ELCC methodology?

No, storage and hybrid resources should not have their NQC value determined using an ELCC methodology. Instead, they should continue to be valued as they are today pending the outcome of the RA Reform Track. The Commission is currently evaluating two primary slice-of-day proposals in the Reform Track, one of which would count storage based on its capacity and duration as shown by the LSE provided the LSE demonstrates sufficient excess capacity in other hours to charge the storage. This approach appears to value the contribution of storage resources more appropriately than an ELCC because it recognizes its contribution to reliability as a dispatchable resource and directly accounts for the need to charge storage, an increasingly important consideration as the grid becomes more reliant on storage. The Commission should not adopt ELCC values for storage and hybrid NQCs at this time given the ongoing work in the Reform Track to address resource counting. Instead, the Commission should continue to use the existing methodologies until a slice-of-day framework is adopted in the Reform Track.

In addition to the ongoing developments in the Reform Track, the ELCC methodology for hybrids requires additional clarification and review before the ELCC values can be adopted. First, staff must clarify the charging limitation assumptions for hybrid resources included in the model and validate that these assumptions in SERVM match reality to the extent practicable. The LOLE study indicates that charging is limited for some hybrid resources.[14] The study should elaborate on the reasons behind these constraints, as they may be the cause of the low ELCC for hybrids in the winter relative to the storage ELCC. If the justification for the constraint is the Federal Investment Tax Credit (ITC), then this should not be treated as a hard constraint. As long as storage charges 75% from renewables, the storage portion of hybrid can continue to qualify for the ITC, pro-rated at the portion charged from renewables. Hybrid charge and discharge patterns are dictated largely by the ITC, which penalizes grid charging. A production cost model generally dispatches resources based on price and may not capture the opportunity cost of foregone ITC credits or real-world grid charging behavior.

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[14] LOLE Study at 15.

To validate the results of SERVM's hybrid dispatch, staff should compare hourly charging and discharging hybrid behavior from CAISO settlement ("real") data versus modeled data, ensure that they approximately match, and adjust model inputs accordingly to correct any large discrepancies. Staff could release a table showing charge and discharge patterns by month and hour to allow stakeholders to ensure that hybrids are being charged and discharged in a way that reflects the real-world ITC incentives.

Second, staff's presentation defines the ELCC percent as Perfect Capacity MW divided by the installed capacity MW of a generator.[15] However, the term "installed capacity" is ambiguous for hybrid resources. It is unclear if this means that the denominator for the ELCC calculation of a hybrid is the sum of the solar installed capacity and storage installed capacity, or whether it is the point of interconnection (POI) capacity (which may be lower than that sum). The Commission should use the POI capacity as the denominator for hybrid ELCC. The POI represents the maximum rate at which the hybrid resource can deliver energy to the grid and is thus analogous to the definition of installed capacity for a single standalone resource. To be consistent with its definition of ELCC across resource types, the Commission should use the POI as the denominator in the ELCC calculation for hybrid resources.

In summary, the Commission should not adopt ELCC values for storage and hybrid RA counting. Proposals in the Reform Track around slice-of-day provide alternative methodologies for valuing storage that more appropriately reflect the capability of the resource and more clearly account for ensuring sufficient energy to charge the storage. Alternatively, if the result of the Reform Track is to expand the use of ELCCs, clarifications are needed around the methodology for valuing hybrids in order to assess the appropriateness of ELCC methodology used.

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[15] Presentation at 11.

9. Should the PRM be static across the year or vary monthly (or seasonally)? How should PRM and ELCC values be allocated across months? Via month specific studies or via some allocation method?

CalCCA has no comments at this time.

10. Should forced outage rates on thermal resources be included in setting their QC value? In other words, should the PRM be set using a UCAP or installed capacity (ICAP) framework? If an UCAP framework is used should the forced outage rates also include ambient derates?

Forced outage rates including ambient derates should be included in setting thermal resources' QC value using a UCAP framework so long as UCAP is accurately reflected in the PRM. CalCCA generally supports the UCAP concept given the benefits described below. CalCCA also supports including ambient derates in the UCAP value so that restrictions in output due to weather conditions are attributed to the units whose output is affected. The Effective Forced Outage Rate of Demand (EFORd) calculation assesses if units are available when they are "in demand." If a resource is not fully available due to ambient derates when it is needed, this should be accounted for in its UCAP value. Because ambient derates may vary by season, the Commission could consider calculating seasonal forced outage rates and UCAP values, as proposed by the CAISO in its UCAP proposal.[16] UCAP offers several benefits. First, attributing unit specific performance metrics into resources' capacity values rather than including a forced outage percentage in the PRM allows LSEs to assess the reliability of resources when making contracting decisions. Second, it allows the CAISO to eliminate its Resource Adequacy Availability Incentive Mechanism (RAAIM) tool, which has proven to be ineffective at incenting forced outage substitution. Finally, UCAP provides the right incentives for generators to conduct planned maintenance to reduce the chance of forced outages occurring when the system needs the resource. The Commission should ensure any adoption of UCAP is coordinated with the

[16] *Future of Resource Adequacy Working Group Report*, (R.21-10-002), Feb. 2022, at 52-58.

CAISO and should ensure the implementation of UCAP does not have unintended impacts to existing contracts.

11. Should the load forecast used to set RA requirements be based on the monthly load forecast produced by SERVM or the IEPR (as done today)? Should the PRM calculation (presented in Table 10) be based on the IEPR forecast as opposed to the SERVM monthly load forecast? Why or why not?

The Commission should base RA requirements and the PRM calculation on the IEPR load forecast for consistency and transparency. The IEPR forecast is used to derive LSE RA obligations and the PRM should be calculated based on the same forecast used to derive RA obligations. The development of the IEPR forecast is more transparent than the forecast produced by SERVM, as the CEC conducts an annual stakeholder process with opportunity for public review and comment. Using the more transparent forecast would allow parties to validate results of the PRM calculation more easily. For these reasons, the Commission should base both the RA requirements the PRM calculation on the IEPR forecast as opposed to the monthly load forecast produced by SERVM.

III. COMMENTS TO THE FINAL REPORT

In D.21-06-029, the Commission recognized the value of continuing an LCR Working Group given the substantial increase in the Greater Bay Area LCR requirement and recommended CalCCA and PG&E co-lead the LCR Working Group process. The Commission directed the LCR Working Group to evaluate and make recommendations on the following topics:

- Potential modifications to the current LCR timeline or processes to allow more meaningful vetting of the LCR study results;
- Inclusion of energy storage limits in the LCR report and its implications on future resource procurement; and

- How best to harmonize the Commission's and CAISO's local resource accounting rules.[17]

The Final Report was filed on February 28, 2022, outlining the discussion in the working group and recommendations by working group participants. The Final Report found that the working group process provided significant clarity on the LCR study process and assumptions. The Final Report also flagged that significant additional work is required to leverage the crossover between the LCR process and parallel planning processes, especially with the IRP process and TPP. Recommendations in the Final Report also addressed how the Commission and CAISO should coordinate to ensure stakeholders are engaged and sufficiently informed of LCR milestones. Finally, the Final Report urged parties to fully consider the relationship between the local RA construct and state policy efforts to ensure both objectives are balanced. [18] CalCCA supports the findings in the Final Report, including the importance of leveraging the crossover between the LCR, the IRP and TPP processes, coordinating communication around LCR milestones, and considering the relationship between the local RA construct and state policy efforts.

A. Coordinated Efforts Between the IRP and TPP are Required to Ensure the State can Meet its LCR in a Cost-Effective Manner with Carbon-Free Resources

The California electricity sector is currently undergoing a major transition towards 100 percent clean electricity. The ability for the state to meets local area reliability needs with clean resources will impact the state's progress towards meeting its ambitious clean electricity goals. The ability to retire fossil fuel resources in local areas will depend either on eliminating

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[17] *Decision Adopting Local Capacity Obligations for 2022-2024, Flexible Capacity Obligations for 2022, and Refinements to the Resource Adequacy Program* (R.19-11-009), June 24, 2021 (D.21-06-029), at 13-14.

[18] Final Report, Attachment 1-3.

transmission constraints limiting the amount of resources that can serve the local area or bringing enough effective carbon-free resources online in the local area to replace the fossil-fuel resource. As demonstrated by the local requirement increase in the greater bay-area identified in the 2022 LCR, effectiveness of the local area resources available in the local areas can have significant impacts on the amount of RA resources that must be procured to meet the local requirement.[19] However, currently LSEs cannot easily identify which resource locations will be effective at meeting the local need when making decisions around new resource procurement.

Additional coordinated efforts between the IRP and TPP processes are needed to ensure resource and transmission build, cost-effectively address local area reliability needs while allowing fossil fuel resources in local areas to retire in order to meet California's policy goals. As recommended in CalCCA's Informal Comments, the following questions need to be considered to make decisions around whether resource or transmission build most cost-effectively addresses the LCR with clean electricity goals in mind:

- If the current resources have significantly low effectiveness factors, where should new resources locate to be more effective?
- What are the transmission alternatives and how much do they cost compared to the large increase in local RA requirement or a new resource at a more effective location?
- What information can be provided to the market about where new resources are needed based upon local area contingencies that are highly complex?[20]

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19 *See, California Community Choice Association Informal Comments On The Local Capacity Requirement Working Group, February 2, 2022,* Feb. 24, 2022 (CalCCA Informal Comments) for additional discussion regarding the increased greater-bay area local requirements.

20 *Id*.

B. CalCCA Supports Noticing the Service List of Key LCR Study Process Milestones to Allow for More Meaningful Input to the LCR Study Results

CalCCA supports the Final Report's recommendation that the Commission notice CAISO LCR stakeholder process activity on the Commission's service list.[21] Noticing the service list of key LCR dates and milestones would allow for reach a potential broader audience of stakeholders and allow for more robust participation in the CAISO's LCR stakeholder process.

IV. CONCLUSION

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

Respectfully submitted,

Evelyn Kahl

Evelyn Kahl
General Counsel to the
California Community Choice Association

March 14, 2022

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21 Final Report, Attachment 1-3.

APPENDIX A
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE LOCAL CAPACITY REQUIREMENT (LCR) FINAL WORKING GROUP REPORT AND ENERGY DIVISION'S LOSS OF LOAD EXPECTATION STUDY

CAISO PLEXOS IMPLEMENTATION OF SIMULTANEOUS IMPORT CONSTRAINT

Collection	Parent Object	Child Object	Property	Value	Units	Band	Timeslice	Action	Scenario	Memo	Category
Constraints	WECC	CAISO Import	Sense	<=	-	1		=			Import Limitations
Constraints	WECC	CAISO Import	RHS	11665	-	1	!ISOImport	=	CAISO IRP19		Import Limitations
Constraints	WECC	CAISO Import	RHS	5500	-	1	ISOImport	=	IRP21a_38MMT	reduce import from 5k to 4k+1457	Import Limitations
Generator.Constraints	Apex CC	CAISO Import	Reserve Provision Coefficient	1	MW	1		=			Import Limitations
Generator.Constraints	DesertStarCC-Total	CAISO Import	Reserve Provision Coefficient	1	MW	1		=			Import Limitations
Generator.Constraints	Mesquite CC1	CAISO Import	Reserve Provision Coefficient	1	MW	1		=			Import Limitations
Generator.Constraints	MesquiteCC2-Total	CAISO Import	Reserve Provision Coefficient	1	MW	1		=			Import Limitations
Generator.Constraints	Hoover - CAISO	CAISO Import	Reserve Provision Coefficient	1	MW	1		=			Import Limitations
Generator.Constraints	LineUpAS	CAISO Import	Reserve Provision Coefficient	1	MW	1		=			Import Limitations
Generator.Constraints	Wyoming_Wind	CAISO Import	Generation Coefficient	-0.7	MW	1		=			Import Limitations
Line.Constraints	APS_to_SCE	CAISO Import	Flow Coefficient	1	MW	1		=			Import Limitations
Line.Constraints	APS_to_SDGE	CAISO Import	Flow Coefficient	1	MW	1		=			Import Limitations
Line.Constraints	BPA_to_PG&E_VLY	CAISO Import	Flow Coefficient	1	MW	1		=			Import Limitations
Line.Constraints	CFE_to_SDGE	CAISO Import	Flow Coefficient	1	MW	1		=			Import Limitations
Line.Constraints	IID_to_SCE	CAISO Import	Flow Coefficient	1	MW	1		=			Import Limitations
Line.Constraints	IID_to_SDGE	CAISO Import	Flow Coefficient	1	MW	1		=			Import Limitations
Line.Constraints	LDWP_to_SCE	CAISO Import	Flow Coefficient	1	MW	1		=			Import Limitations
Line.Constraints	NEVP_to_SCE	CAISO Import	Flow Coefficient	1	MW	1		=			Import Limitations
Line.Constraints	PACW_to_PG&E_VLY	CAISO Import	Flow Coefficient	1	MW	1		=			Import Limitations
Line.Constraints	PG&E_VLY_to_SMUD	CAISO Import	Flow Coefficient	-1	MW	1		=			Import Limitations
Line.Constraints	PG&E_VLY_to_SPP	CAISO Import	Flow Coefficient	-1	MW	1		=			Import Limitations
Line.Constraints	PG&E_VLY_to_TIDC	CAISO Import	Flow Coefficient	-1	MW	1		=			Import Limitations
Line.Constraints	SCE_to_SPP	CAISO Import	Flow Coefficient	-1	MW	1		=			Import Limitations
Line.Constraints	SCE_to_WALC	CAISO Import	Flow Coefficient	-1	MW	1		=			Import Limitations
Line.Constraints	DI_CANWHydro	CAISO Import	Flow Coefficient	1	MW	1		=			Import Limitations
Line.Constraints	DI_Hoover (ISO)_SCE	CAISO Import	Flow Coefficient	1	MW	1		=			Import Limitations
Line.Constraints	DI_PaloVerd 1-3_SCE	CAISO Import	Flow Coefficient	1	MW	1		=			Import Limitations
Line.Constraints	DI_IID_SCE_RPS	CAISO Import	Flow Coefficient	1	MW	1		=			Import Limitations
Line.Constraints	DI_LDWP_SCE_RPS	CAISO Import	Flow Coefficient	1	MW	1		=			Import Limitations
Line.Constraints	DI_OOSRPS_AZ	CAISO Import	Flow Coefficient	1	MW	1		=			Import Limitations
Line.Constraints	DI_OOSRPS_N BPA	CAISO Import	Flow Coefficient	1	MW	1		=			Import Limitations
Line.Constraints	DI_OOSRPS_NM	CAISO Import	Flow Coefficient	1	MW	1		=			Import Limitations
Line.Constraints	DI_OOSRPS_S CFE	CAISO Import	Flow Coefficient	1	MW	1		=			Import Limitations
Line.Constraints	DI_OOSRPS_S NEVP	CAISO Import	Flow Coefficient	1	MW	1		=			Import Limitations
Line.Constraints	DI_OOSRPS_S TEPC	CAISO Import	Flow Coefficient	1	MW	1		=			Import Limitations
Timeslices	WECC	ISOImport	Include	Yes	Yes/No	1	M6-9,H17-22	=			-

California Community Choice Association

SUBMITTED 03/16/2022, 03:42 PM

Contact

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1. Please provide your organization's comments on the imbalance reserve demand curve topic:

The California Community Choice Association (CalCCA) appreciates the opportunity to comment on the Day-Ahead Market Enhancements (DAME) Workshop held on March 2, 2022. CalCCA's comments focus on the proposals' impact on the Resource Adequacy (RA) must-offer obligations.

2. Please provide your organization's comments on the market power mitigation topic:

CalCCA has no comments at this time.

3. Please provide your organization's comments on the accounting for energy offer price in upward capacity procurement topic:

CalCCA has no comments at this time.

4. Please provide your organization's comments on the resource adequacy real-time must offer obligation topic:

CalCCA appreciates the CAISO reconsidering its proposal to remove the resource adequacy real-time must offer obligation. The CAISO's proposal to have the Local Regulatory Authority (LRA) elect to require the real-time must offer obligation, however, creates challenges around enforceability. Because the CAISO is the entity that accepts the bids offered into the market, there is no way to ensure RA resources with an offer obligation imposed by the LRA is offering in real-time until after the fact. If the LRA determines there is a reliability benefit to maintaining the real-time must offer obligation, the CAISO should enforce the must offer obligation and insert bids for resources with a must offer obligation so that bids are in fact available in real-time.

CalCCA supported the transition period in the previous proposal that would require RA resources to bid zero dollars into the Residual Unit Commitment (RUC) until the Extended Day-Ahead Market (EDAM) is implemented to allow time for parties to consider alternatives. Now that EDAM and DAME's planned implementation dates are on the same timeline and there is no time for a transition period, CalCCA requests the CAISO consider this issue in a coordinated manner between EDAM and DAME. CalCCA agrees with the CAISO that California resources should not effectively provide capacity to other balancing authorities at zero cost; a potential result of maintaining the zero dollar bidding requirement. The CAISO and stakeholders should consider alternatives within the EDAM initiative so capacity paid to be available through real-time are not paid for twice; once through bi-lateral RA transactions and again through imbalance reserve payments. It is not clear the benefits of the DAME proposal outweigh the costs resulting from these impacts to RA. Additional discussion is needed to ensure imbalance reserves paid for by California LSEs will be available to serve California load under the context of EDAM.

5. Please let us know if you have additional comments (optional):

CalCCA has no additional comments at this time.

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R2102014

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

Order Instituting Rulemaking to Address Energy Utility Customer Bill Debt Accumulated During the COVID-19 Pandemic.	R.21-02-014

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION REQUIRING DEVELOPMENT OF COMMUNITY BASED ORGANIZATION CASE MANAGEMENT PILOT PROGRAM TO REDUCE ARREARAGES ASSOCIATED WITH THE COVID-19 PANDEMIC

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March 24, 2022

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SUMMARY OF RECOMMENDATIONS

CalCCA recommends the following revisions to the Proposed Decision:

- ✓ Allow one representative from each community choice aggregator (CCA) (and not only a representative from one CCA in each of the investor-owned utility's service territories) participate in the Community Based Organization (CBO) Pilot Working Group;

- ✓ Require the CBO Pilot Working Group to ensure that CBO training for case management services incorporate CCA programs and CCA customer needs; and

- ✓ Include CCA unbundled customers in the targeted communities for the CBO Pilot.

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Address Energy Utility Customer Bill Debt Accumulated During the COVID-19 Pandemic.	R.21-02-014

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION REQUIRING DEVELOPMENT OF COMMUNITY BASED ORGANIZATION CASE MANAGEMENT PILOT PROGRAM TO REDUCE ARREARAGES ASSOCIATED WITH THE COVID-19 PANDEMIC

The California Community Choice Association (CalCCA)[1] submits these Comments, pursuant to Rule 14.3(a) of the California Public Utilities Commission (Commission) Rules of Practice and Procedure, on the proposed *Decision Requiring Development of Community Based Organization Case Management Pilot Program to Reduce Arrearages Associated With the COVID-19 Pandemic* (Proposed Decision), dated March 4, 2022.

I. INTRODUCTION

CalCCA appreciates the Commission's ongoing efforts to address the significant customer utility debt remaining even after the implementation of various programs available for COVID-19 arrearage and bill relief. The Arrearage Management Plans,[2] COVID-19 Payment

[1] California Community Choice Association represents the interests of 23 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, 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] Decision (D.) 20-06-003, *Phase I Decision Adopting Rules and Policy Changes to Reduce Residential Customer Disconnections for the Larger California-Jurisdictional Energy Utilities,* R.18-07-005 (Jun. 11, 2020) (establishing the Arrearage Management Plans to assist eligible customers with eliminating large unpaid arrearages while avoiding disconnection).

Plans,[3] along with other state and federal programs for COVID-19 debt relief are intended to help customers pay their overdue energy bills. In addition, the California Arrearage Payment Program (CAPP) is distributing nearly $695 million in relief to customers of investor-owned utilities (IOU), community choice aggregators (CCA), and direct access (DA) providers.[4] Of the nearly $695 million allocated to the IOUs, over $55 million is being distributed to customers of 23 CCAs.[5] Such a large allocation can be attributed to the fact that CCA customers account for over four million customer accounts, or approximately 32 percent of the load, within the IOU territories.[6]

CalCCA supports the Commission's establishment of a Community Based Organization (CBO) Case Management Pilot Program (CBO Pilot) to assist and provide case management services to the large number of customers with remaining arrearages even after the CAPP assistance. Given the myriad of programs available for relief, as well as choices provided by IOUs *and* CCAs, customer confusion over understanding and resolving utility bill debt is widespread. CalCCA also supports the Proposed Decision's requirements that a working group (CBO Pilot Working Group) be convened to develop and oversee the CBO Pilot. To ensure the effectiveness of the CBO Pilot, CalCCA recommends the following revisions to the Proposed Decision:

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3 D.21-06-036, *Decision Addressing Energy Utility Customer Bill Debt Via Automatic Enrollment in Long Term Payment Plans,* R.21-02-014 (Jun. 24, 2021) (allowing customers up to two years to pay off debt incurred during the COVID-19 pandemic).

4 *See* CAPP Program Notice No. 2021-06-E2 (Nov. 2, 2021) (total allocations designated for each CCA); CAPP Program Notice No. 2021-10-R (Dec. 28, 2021) (total allocations designated for Direct Access customers).

5 *See* CAPP Program Notice No. 2021-06-E2 (Nov. 2, 2021), at 5 (list of CCA arrearages and CAPP allocations).

6 This number will rise by close to one million customers as San Diego Gas & Electric Company's customers' transition to San Diego Community Power in 2022.

- ✓ Allow one representative from each CCA (and not only a representative from one CCA in each of the IOUs' service territories) to participate in the CBO Pilot Working Group;
- ✓ Require the CBO Pilot Working Group to ensure that CBO training for case management services incorporate CCA programs and CCA customer needs; and
- ✓ Include CCA unbundled customers in the targeted communities for the CBO Pilot.

II. THE PROPOSED DECISION MUST BE REVISED TO ALLOW ONE REPRESENTATIVE FROM EACH CCA TO PARTICIPATE IN THE CBO PILOT WORKING GROUP

To ensure its effectiveness, the CBO Pilot Working Group must include representatives from all entities involved, including all CCAs that choose to participate. Attachment A to the Proposed Decision requires Pacific Gas and Electric Company (PG&E) to convene the CBO Pilot Working Group with a variety of stakeholder representatives, including one representative from each IOU, and from each IOU service territory, one CCA representative.[7] Therefore, in the CBO Pilot Working Group, all three IOUs will have a representative, but only three out of the over 23 CCAs operating within the IOU service territories will be represented.

CCAs are distinct entities, each with unique policies and programs. One CCA in an IOU's territory cannot adequately represent or communicate the diverse programs or needs of each CCA's customers. In addition, each CCA can contribute invaluable knowledge regarding local CBO offerings as well as the local community. While one representative from various non-LSE stakeholder groups may be sufficient, all load-serving entities (including IOUs and CCAs) should be permitted to participate in the CBO Pilot Working Group to adequately represent the interests of its customers and its program offerings. Accordingly, Attachment A of the Proposed Decision should be revised to allow one representative from each CCA.

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[7] Proposed Decision, Attachment A, §§ 2(a) and (b).

III. THE COMMISSION SHOULD REQUIRE THE CBO PILOT WORKING GROUP TO ENSURE THAT CBO TRAINING FOR CASE MANAGEMENT SERVICES INCORPORATE CCA PROGRAMS AND CCA CUSTOMER NEEDS

Case management services provided through the CBO Pilot must include effective and accurate messaging regarding *all* programs available to a customer in need, including those provided by an IOU *or a CCA.* The Proposed Decision states that "effective case management requires CBOs to consider all available programs that may reduce customer utility bill debt, immediately and ongoing."[8] The Commission requires the CBO Pilot Working Group to "consider this problem and propose solutions in their final proposal," and to "develop and include in the final proposal strategies to build CBO capacity for case management of the multiplicity of assistance programs."[9] However, the Proposed Decision fails to mention CCA programs or CCA unbundled customers in connection with these strategies. The CBO Pilot Working Group must develop and require fair, accurate, and effective communications from CBOs to customers, which account for whether a customer is an IOU or CCA customer, and all of the applicable programs available to each customer.

The Proposed Decision should be modified as set forth in Appendix A hereto to ensure that CCA programs and customers are fairly represented. CalCCA also recommends revising section 3 of the Straw Proposal in the Proposed Decision's Attachment B to add the following question for the CBO Pilot Working Group to consider:

> f. <u>How will the CBO Pilot incorporate messaging and written training materials formulated to assist both IOU bundled, and CCA unbundled, customers and to fairly, accurately, and effectively communicate the programs available to such customers.</u>

In addition, section 9 of the Straw Proposal should be revised as follows:

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8 Proposed Decision at 20-21.

9 *Id.* at 21, 30.

9. **Contract Administration.** Each IOU serving as a contract administrator will contract with, and pay all CBOs selected for the CBO Pilot. As contract administrator, each IOU will also

   a. establish a checklist of IOU and/or CCA programs and services for CBOs to utilize in reporting options considered for each customer
   b. provide initial training and ongoing consultation for each contracted CBO that includes the checklist set forth in subsection a. above, and ensures fair, accurate and effective communications regarding programs available to IOU and CCA customers
   c. participate in and support the CBO Pilot Working Group
   d. allow CCAs to participate in the development of any written materials being provided to CBOs to assist in case management services in their service area.

CalCCA further recommends that the CBO Pilot Working Group develop any other measures necessary to ensure that IOU *and* CCA customers can fairly and effectively navigate *all* available program and resource options.

IV. THE PROPOSED DECISION'S RECOMMENDATIONS REGARDING COMMUNITIES TARGETED FOR THE PILOT SHOULD INCLUDE CCA CUSTOMERS

The Proposed Decision should ensure that the criteria for targeting communities that would benefit from the CBO Pilot are inclusive of customers within each IOU *and* CCA service territories. The Proposed Decision provides target-vulnerable IOU communities for the CBO Pilot, based on the Commission's metrics established in the Affordability proceeding, R.18-07-006.[10] Attachment D provides a list of targeted communities for the CBO pilot based on those metrics. The Proposed Decision and Attachment D, however, ignore that many customers within the communities listed, as well as many other customers within communities outside of the listed communities, are CCA customers. Importantly, the Proposed Decision, as well as the Attachment B straw proposal, should address how CCA customers within the targeted populations will be

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10 *Id.* at 23-24, Attachment D (list of targeted communities).

included in the CBO Pilot. In addition, the Commission should broaden the reach of the CBO Pilot to include both IOU *and* all CCA service territories.

V. CONCLUSION

CalCCA appreciates the opportunity to submit these Comments and requests adoption of the recommendations proposed herein. For all the foregoing reasons, the Commission should modify the proposed decision as provided in Attachment A.

Respectfully submitted,

Evelyn Kahl

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

March 24, 2022

ATTACHMENT A

PROPOSED CHANGES TO FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ATTACHMENTS A AND B

FINDINGS OF FACT

7. CBO case management is a promising approach to help certain customers access the variety of utility and community choice aggregator relief programs and to combine the varied utility and community choice aggregator relief programs to their advantage.

CONCLUSIONS OF LAW

6. It is reasonable to consider development of a CBO Pilot for a specific number of residential utility and community choice aggregator customers, to be proposed by the CBO Pilot Working Group over a two-year period during the calendar years 2022, 2023 and 2024 that may be funded through a surcharge on all ratepayer classes.

REVISIONS TO PROPOSED DECISION, ATTACHMENT A

2. **Composition**

b. ~~From each IOU service territory, one~~From each Community Choice Aggregator (CCA) that chooses to participate, one representative.

REVISIONS TO PROPOSED DECISION, ATTACHMENT B

3.

f. How will the CBO Pilot incorporate messaging and written training materials formulated to assist both IOU bundled, and CCA unbundled, customers to fairly, accurately, and effectively communicate the programs available to such customers.

9. **Contract Administration.** Each IOU serving as a contract administrator will contract with, and pay all CBOs selected for the CBO Pilot. As contract administrator, each IOU will also

a. establish a checklist of IOU and/or CCA programs and services for CBOs to utilize in reporting options considered for each customer
b. provide initial training and ongoing consultation for each contracted CBO that includes the checklist set forth in subsection a. above, and ensures fair, accurate and effective communications regarding programs available to IOU and CCA customers
c. participate in and support the CBO Pilot Working Group
d. allow CCAs to participate in the development of any written materials being provided to CBOs to assist in case management services in their service area.

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

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	R.21-10-002

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING
SEEKING COMMENTS ON THE FUTURE OF RESOURCE ADEQUACY
WORKING GROUP REPORT**

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March 24, 2022

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SUMMARY OF RECOMMENDATIONS

- The Commission should adopt the 24-hour slice RA framework only if modifications are made to allow for the transactability of hourly RA obligations and products;
- The Commission should implement the 24-hour slice RA framework no earlier than for RA Compliance Year 2025 to ensure the development of key details;
- The Commission must not adopt proposals that would place mandatory hedging requirements on RA procurement; and
- The Commission and the CAISO should coordinate to adopt the same UCAP methodology.

**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 ADMINISTRATIVE LAW JUDGE'S RULING
SEEKING COMMENTS ON THE FUTURE OF RESOURCE ADEQUACY
WORKING GROUP REPORT**

The California Community Choice Association[1] (CalCCA) submit these Comments pursuant to the schedule set forth in the *Administrative Law Judge's Ruling Seeking Comments on the Future of Resource Adequacy Working Group Report and the Local Capacity Requirement Working Group Report* (Ruling), issued on March 4, 2022.

I. INTRODUCTION

CalCCA appreciates the opportunity to comment on the Future of Resource Adequacy Working Group Report[2] (Working Group Report). The Working Group Report reflects the robust discussions that took place over ten workshops aimed at refining Pacific Gas and Electric Company's (PG&E's) slice-of-day proposal at the direction of Decision (D.) 21-07-014. Through the

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1 California Community Choice Association represents the interests of 23 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, 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 *Future of Resource Adequacy Working Group Report, Track 3.B2 of the RA Proceeding*, R.21-10-002 (Feb. 2022) (Working Group Report).

workshop process, parties generally coalesced around two alternatives for slice-of-day reform. First is a 24-hour slice proposal put forth by Southern California Edison Company (SCE). This proposal would require each load-serving entity (LSE) to demonstrate that for each month, it has procured enough capacity to meet its load profile plus a planning reserve margin (PRM) in all 24 hours on the "worst day" of the month.[3] This proposal would also count wind and solar using hourly profiles and would include a storage charging sufficiency component. Second is a 2-slice proposal put forth by Gridwell. This proposal would require each LSE to demonstrate it has procured enough capacity to meet its load ratio share of California Independent System Operator Corporation (CAISO) gross peak load plus a PRM and net peak load plus a PRM. This proposal would expand the use of Effective Load Carrying Capacity (ELCC) for Resource Adequacy (RA) counting to batteries and hydro and would adjust wind and solar values to values they can "reasonably [be] expected to operate in the test hour," although this is undefined.4

D.21-07-014 outlined five principles that should be addressed in a reformed RA framework. These principles are:

1. To balance ensuring a reliable electrical grid with minimizing costs to customers;
2. To balance addressing hourly energy sufficiency for reliable operations with advancing California's environmental goals;
3. To balance granularity and precision in meeting hourly RA needs with a reasonable level of simplicity, and transactability;
4. To be implementable in the near-term (*e.g.,* 2024); and
5. To be durable and adaptable to a changing electric grid.[5]

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[3] *See* Working Group Report at 10: "SCE proposes to initially define the "worst day" as the day of the month that contains the hour with the highest coincident peak load forecast. This could evolve over time if some other attribute (*e.g.*, steepest ramping requirement) is found to be more challenging to reliability than the coincident peak."

[4] *Id.* at 34.

[5] D.21-07-014, Ordering Paragraph 2.

If the 24-hour slice proposal is modified to improve transactability, the 24-hour slice proposal best meets these principles. The 24-hour slice proposal evolves resource counting rules to more appropriately account for the reliability contribution of renewable and energy limited resources across the day. It is a more durable approach because it will address energy needs in each hour as the grid evolves over time and will ensure enough RA capacity is shown to charge storage. Without enhancements to the proposal to allow for transactability of products on an hourly basis, however, the 24-hour slice proposal will likely fall short of meeting principles one, two, and three for the reasons described in Section A below. The California Public Utilities Commission (Commission) should allow the necessary time for Energy Division and parties to fully develop transactability enhancements and other necessary components of the 24-hour slice proposal before final adoption. A phased implementation approach that does not consider transactability at the outset could have unintended consequences detrimental to customer costs and California's environmental goals.

D.21-07-014 directed parties to also consider a requirement that would link RA to a resource's bidding behavior with the stated goal of increasing cost-effectiveness of RA.[6] PG&E presented two separate proposals; a variable cost hedge proposal that would require a rebate to LSEs any energy market revenues that exceed variable costs and a price cap rebate proposal that would require a resource to pay the LSE a rebate when the locational marginal price is above a certain price cap. Instituting a mandatory hedging component for RA raises a number of concerns around the lack of a clear problem statement, increased ratepayer costs, and administrative complexity. The Commission should not adopt mandatory hedging mechanisms on RA resources.

Finally, the CAISO submitted a proposal that would incorporate forced outages into net qualifying capacity (NQC) values through an unforced capacity (UCAP) framework. CalCCA

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6 D.21-07-014, at 27.

supports a UCAP framework but notes the Energy Division developed its own UCAP values in its *Loss of Load Expectation and Effective Load Carrying Capability Study Results for 2024* (LOLE Study) that differ from the methodology proposed by the CAISO.[7] The Commission and the CAISO should work together to ensure the methodology used to assess forced outage rates is consistent and that the Commission processes and the CAISO processes are aligned under a UCAP framework.

In summary, CalCCA offers the following comments described in detail below to the Working Group Report:

- The Commission should adopt the 24-hour slice RA framework only if modifications are made to allow for the transactability of hourly RA obligations and products;
- The Commission should implement the 24-hour slice RA framework no earlier than for RA Compliance Year 2025 to ensure the development of key details;
- The Commission must not adopt proposals that would place mandatory hedging requirements on RA procurement; and
- The Commission and the CAISO should coordinate to adopt the same UCAP methodology.

These recommendations should be adopted to ensure the new framework results in a transactable, reliable, and affordable RA program.

II. COMMENTS TO THE WORKING GROUP REPORT

A. The Commission Should Adopt the 24-Hour Slice RA Framework Only if Modifications are Made to Allow for the Transactability of Hourly RA Obligations and Products

While CalCCA supports adoption of the 24-hour slice proposal, this support is dependent on the ability of LSEs to trade resources and RA obligations on an hourly basis. The 24-hour slice proposal better meets the Commission's principles than the two-slice proposal. Therefore, CalCCA does not support the two-slice proposal. However, without the ability to trade resources and

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[7] *Energy Division Study for Proceeding R.21-10-002, Loss of Load Expectation and Effective Load Carrying Capability Study Results for 2024*, R.21-10-002 (Feb 18, 2022).

obligations on an hourly basis, the 24-hour proposal could also result in significant unintended consequences that make it unworkable. The Commission must adopt the 24-hour slice proposal with the ability for LSEs to adjust resources and obligations hourly to ensure the new RA framework is transactable, cost-effective, and aligns with the state's policy goals.

If the Commission adopts hourly RA obligation and resource trading to enhance transactability of the 24-hour slice framework, SCE's proposal provides a solid framework capable of securing capacity to meet each hour's need as the load shape and resource mix evolve. The proposal would appropriately value each resource's contribution to reliability by valuing resources based on the energy they can provide across the day. As storage becomes a more prevalent resource type, it is important for the future RA framework to properly account for storage resources' capability. The 24-hour proposal does this by allowing LSEs to choose the duration and associated capacity to show the resource and requiring the LSE to also show enough excess capacity to charge the storage.

1. The Commission Must Adopt a Modified 24-Hour Slice Proposal That Allows for Trading of RA Obligations on an Hourly Basis and Resources on an Hourly Basis

Transactability is a key component of the RA program that should be maintained to allow LSEs to meet their compliance obligations simply and efficiently. This is supported by Commission's third principle in D.21-07-014, "To balance granularity and precision in meeting hourly RA needs with a reasonable level of simplicity, and transactability." For an RA framework to meet this third principle, however, the 24-hour slice proposal must be modified. The 24-hour slice proposal as currently defined would not allow resources to be traded in separate hourly blocks. The proposal also does not expressly allow hourly trading of RA obligations. This could significantly challenge LSEs' ability to meet their RA obligations by artificially constraining the RA market and unnecessarily increasing procurement and ratepayer costs; this jeopardizes the Commission's first principle, "To balance ensuring a reliable electrical grid with minimizing costs to customers."[8] In many cases, LSEs' portfolios may not perfectly match their obligations. LSEs must be able to shape their portfolios to match their obligations to minimize customer costs and mitigate against market power in an already constrained RA market. As discussed in the informal comments attached to the Working Group Report by Clean Power Alliance of Southern California (CPA), East Bay Community Energy (EBCE), Marin Clean Energy (MCE), Peninsula Clean Energy (PCE), Pioneer Community Energy (Pioneer), San Jose Clean Energy (SJCE), and Sonoma Clean Power (SCP) (the Collective CCAs), hourly transactability is even more critical for non - investor-owned utility (IOU) LSEs, given D.21-05-030 determined IOUs retain the RA attributes for resources in their portfolio and departed load receives a financial credit in lieu of the RA resource.[9] Without hourly transactability, non-IOU LSEs would be put in the difficult position of procuring artificially scarce supply while the IOU LSEs would be unnecessarily long in most hours.

To demonstrate the challenges that arise without hourly transactability take, for example, LSE A, which needs to procure additional capacity to meet its obligations Hour Ending (HE) 9 through HE 10. Without hourly trading of RA obligations or resources, depending on the resources available in the market, the LSE A may not be able to procure capacity for its two-hour need only. The LSE A may, in some cases, be required to buy capacity from a 24-hour resource for all 24 hours, despite only needing the resource for two. If another LSE, LSE B, has an open position in HE 20 through HE 21, the first LSE A would not be able to sell its excess from the 24-hour resource that it does not need to LSE B. LSE B would be required to purchase additional capacity from an entirely new resource. The result in this example is an artificially constrained RA market which drives up customer costs. It could also result in LSEs potentially needing to hold on to carbon-emitting

8 D.21-07-014, Ordering Paragraph 2.
9 Working Group Report at 186.

resources that are not needed if RA resources could be used more efficiently through hourly trading; this runs counter to the Commission's second principle, "To balance addressing hourly energy sufficiency for reliable operations with advancing California's environmental goals." The 24-hour slice should be adopted with modifications to allow hourly trading of RA obligations and resources.

a. Hourly RA Obligation Trading

In informal comments attached to the Working Group Report, the California Energy Storage Alliance (CESA), PCE and SJCE (collectively, the Joint Parties), offered a simple proposal that would allow LSEs with open positions in some hours to trade those obligations to other LSEs with long positions in those hours.[10] This proposal would allow LSEs to capture diversity benefits when load and generation portfolios are different between the two LSEs by allowing LSEs to "share" resources when they have open positions in different hours instead of doing costly and duplicative procurement. Importantly, the Joint Parties' proposal to trade obligations would not shift the responsibility of serving customer load, it would only shift the compliance obligation. Without hourly RA obligation trading, both LSEs would need to procure separate resources when such procurement is not necessary to meet RA obligations as a whole.

In summary, the Joint Parties propose "LSEs with short positions in some hours would be allowed to trade with others with long positions in those hours to allow resource sharing between the two LSEs with different loads and RA portfolios."[11] The Joint Parties' proposal provides an example and outlines detailed steps for RA showings.[12] These steps would ensure RA obligations are fully accounted for following a trade by requiring both LSEs to document the trade on their RA showing. The LSE trading away its obligation would represent the trade as a megawatts (MW) decrease in its

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10 Working Group Report at 196-205.
11 Final Report at 202.
12 *Id.* at 204-205.

hourly obligation profile and the LSE receiving the obligation would show the trade as a MW increase to its RA portfolio. The MW decrease and MW increase on the LSEs' RA showings must sum to zero and the LSE receiving the obligation would accept all responsibilities for the obligation. The Commission would be responsible for validating trades to ensure no double counting or loss of total RA across hours resulting from load obligation trading. This is very similar to the checks the Commission performs today to ensure that a resource is not being over claimed in meeting RA needs.

RA obligation trading is a critical component for transactability under a 24-hour slice proposal with only minor increases in complexity. Effectively, the only change is that an LSE's load is no longer fixed on the California Energy Commission (CEC) forecast. Instead, it can be modified by trading load among LSEs for the purpose of meeting RA compliance obligations. It will require a mechanism to ensure the CAISO is aware of each LSE's new compliance obligation resulting from the trade. The CAISO currently receives LSEs' compliance obligations from the CEC through the Integrated Energy Policy Report (IEPR) forecast. Under a framework in which LSEs can trade obligations, the Commission would need to communicate the LSEs' new compliance obligations resulting from trades to the CAISO such that the CAISO can validate RA showings against the new obligations. This coordination is well worth the benefits a transactable RA product would provide. Because validation of showings under SCE's proposal will become more complicated than it is today, showings validation will likely need to become automated. Adding a validation of RA obligation trades would add minimal additional complexity beyond what is already contemplated under the 24-hour slice proposal.

Other parties' concerns around RA obligation trading are unfounded. While CLECA[13] raised questions around the need for such a mechanism in its informal comments, LSEs most critically impacted by transactability and responsible for compliance have shown that RA obligation trading will allow for lower transaction costs and avoid duplicative procurement.[14] The Public Advocates Office (Cal Advocates) questions whether LSEs would be able to engage in load trading without a change to Public Utilities (PU) Code 366. Cal Advocates states the PU Code, "allows CCAs to serve their customers and does not provide recourse for a CCA to shift customer load to another LSE."[15] This represents a fundamental misunderstanding of the concept of load obligation trading. As stated above, the Joint Parties' proposal to trade obligations would not shift the responsibility of serving customer load, it would only shift the compliance obligation. CCAs or other LSEs who engage in obligation trading would still be responsible for customer load service. Trading of obligations would have no bearing on the energy provided to the customer. This concept is no different than a CCA trading a resource to another CCA, a common practice under today's RA program.

Some parties have suggested that load trading is not necessary as parties can simply perform swaps where party A provides a resource for a set of hours in exchange for Party B providing a different resource for another set of hours. First, it is not clear that the combination of trading whole resources will address the problems in each individual hour for each party if the parties cannot transact individual hours of the resource. Second, swaps come with additional risk in that the terms and conditions of the swap transaction may not match the terms and conditions of the LSE contract with the root resource. This has been recognized as a significant issue in the central procurement entity (CPE) portion of the RA proceeding and has led to the abandonment of a contract to self-

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13 Working Group Report at 227.

14 *See* informal comments from the Collective CCAs at 183-186, and the Joint Parties at 196-205, in the Working Group Report.

15 Working Group Report at 292.

provide in favor of an attestation where the chain of counterparty risk is reduced to the risk of the original contract for the RA product. Simply put, swaps will not readily address the concerns of optimizing a portfolio to meet a 24-hour requirement and will require the use of other instruments.

b. Hourly Resource Trading

While in their informal comments, the Joint Parties do not take a position on hourly resource trading, CalCCA supports including hourly resource trading in addition to hourly RA obligation trading under the 24-hour slice proposal. This would allow LSEs to trade capacity hourly, rather than being required to hold onto capacity in all hours if it is not needed to meet its obligations. This would enable multiple LSEs to show a resource if their hours of need do not overlap by enabling one LSE long in some hours to trade a resource with another LSE short in the same hours, or to allow each LSE to seek RA capacity from suppliers that directly matches their individual compliance needs. This would allow for the more efficient use of the RA fleet and avoid costly overprocurement.

For example, assume LSE A has procured a 24-hour 50 MW resource, Resource 1, to meet its obligations in HE 1 through HE 19. LSE A does not need the resource in HE 20 though HE 24, so it does not procure it for all 24 hours. LSE B, on the other hand, needs 50 MW of capacity to meet its obligations in HE 20 through HE 24. Resource 1 could then sell its 50 MW of capacity to LSE B in HE 20 through HE 24. This allows both LSEs to meet their obligations with the same resource while not double-counting the resource in any hour.

Table 1: Example LSE A Showing

Resource Name	Shown NQC MW	HE1	…	HE19	HE20	HE21	HE 22	HE 23	HE24
Resource 1	50	50	50	50	0	0	0	0	0

Table 2: Example LSE B Showing

Resource Name	Shown NQC MW	HE1	…	HE19	HE20	HE21	HE 22	HE 23	HE24
Resource 1	50	0	0	0	50	50	50	50	50

Table 3: Example Resource 1 Supply Plan Showing

Resource Name	Shown NQC MW	HE1	…	HE19	HE20	HE21	HE 22	HE 23	HE24
Resource 1	50	50	50	50	50	50	50	50	50

Following the showing, the Commission or the CAISO could then validate the showings to ensure that no resource is shown for the same capacity in multiple hours. The 24 by 7 must offer obligation could be maintained such that resources shown in any hour would still have to offer its capacity 24 by 7 (and not just the hours they were shown in). This approach would ensure no capacity was double-counted and that the CAISO can continue to optimize the dispatch of all RA resources through its market as it does today.

B. The Commission Should Implement the 24-Hour Slice RA Framework no Earlier Than for RA Compliance Year 2025 to Ensure the Development of Key Details

SCE's 24-hour slice proposal provides a high-level framework, but significant details must be developed before implementation to ensure a smooth transition with minimal disruptions to the RA market. The following milestones are necessary for implementation:

- Develop enhancements to transactability through hourly obligation and resource trading processes;

- Establish RA counting for wind and solar based on hourly expected energy profiles;[16]

- Establish RA counting for wind and solar based on hourly expected energy profiles;[17]

- Perform a new LOLE study with RA counting assumptions to determine the appropriate PRM; and

- Allow time for CAISO to conduct its own stakeholder process to align its RA rules with the 24-hour slice framework.

The Commission should not adopt the 24-hour slice framework without the enhancements to transactability discussed in Section A, nor should the Commission implement the 24-hour slice proposal with the intention to phase in transactability components at a later date. Doing so could cause significant market disruption and increased customer costs. Additionally, the PRM must be reevaluated to account for changes to resource counting as new resource counting rules will impact the level of PRM required to achieve a targeted level of reliability. The Commission must therefore perform a new LOLE study using wind and solar profiles used in the new RA counting rules. As such, CalCCA recommends the following implementation timeline that would provide one additional to ensure the framework is fully developed prior to implementation:

- **June 2022:** Commission Decision to move forward with the 24-hour slice proposal and direct parties to develop transactability enhancements to allow hourly RA obligation trading and hourly resource trading;

- **Summer 2022 – End of 2022**:

    - Energy Division conducts public workshops to develop transactability enhancements (i.e., hourly trading of RA obligations and hourly trading of

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16 *See* Working Group Report at 9: SCE states "**Solar and wind** will count based on their hourly expected capacity profiles—**specific methodology** *(e.g.*, exceedance, hourly ELCC, or other) **to be determined in subsequent forum.**"

17 *See* Working Group Report at 9: SCE states "**Solar and wind** will count based on their hourly expected capacity profiles—**specific methodology** *(e.g.*, exceedance, hourly ELCC, or other) **to be determined in subsequent forum.**"

resources), establish RA counting for wind and solar, and refine procedures under new structure; and

  - Following the establishment of RA counting rules, Energy Division conducts LOLE study to determine the PRM under slice-of-day framework;

- **January 2023 – March 2023:** Conduct public workshops to vet LOLE study and PRM results;
- **March 2023:** Party comment and reply comment on transactability enhancements, RA counting for wind and solar, LOLE study, and PRM results;
- **June 2023:** Commission Decision adopts transactability enhancements, RA counting for wind and solar, and PRM results;
- **Summer 2023 – Spring 2024:** LSEs test procedures in coordination with Energy Division and Energy Division assesses RA cost and pricing impacts;
- **End of October 2024:** LSEs submit year-ahead showings; and
- **January 1, 2025:** RA compliance year begins.

This timeline will allow Energy Division and parties time to ensure the 24-hour slice proposal is fully developed prior to implementation. It will also allow LSEs sufficient time to conduct orderly procurement under the new requirements and, in collaboration with Energy Division, test the new procedures to ensure a straightforward showing process. Taking additional time would also allow time for Energy Division to conduct an assessment of RA cost and pricing impacts of the new framework or make any necessary adjustments following its initial adoption of the slice-of-day framework.

C. The Commission Must not Adopt Proposals That Would Place Mandatory Hedging Requirements on RA Procurement

D.21-07-014 states, "We find it critical that a future framework include a component that links RA to a resource's energy bidding behavior so as to increase the cost-effectiveness of RA."[18] The Commission cites a decline in IOU-held tolling contracts, tightening supply in the West, and

[18] D.21-07-014 at 27.

lack of adequate market power mitigations measures in the CAISO market as justification for such a mechanism.[19] While the Commission's concerns are around the cost-effectiveness of the RA program, introducing mandatory requirements on RA resources to hedge against exposure to energy costs would not result in the most cost-effective outcome for customers, nor would it make any significant improvements to reliability.

Hedging requirements on RA resources will not result in the most cost-effective outcome for customers and should not be adopted. LSEs already utilize physical and financial hedges to reduce exposure to energy price volatility. LSEs are in the best position to choose their hedging strategies that work best for their portfolio and adopting a uniform methodology for hedging against energy prices would be duplicative to what LSEs are already doing. Because LSEs already choose how to hedge their RA portfolios, if the best way to hedge was to have RA contract with a strike price, LSEs would already be using these mechanisms. This indicates proposals in this proceeding are not the best way to meet RA needs and hedging needs. Therefore, establishing uniform requirements would likely only result in less effective hedging. Hedging is not one-size-fits all and it is not free. LSEs are the only ones with the ability to evaluate for themselves the level of hedge and the mechanisms to accomplish those hedges needed to protect their customers from energy price spikes.

Instead of developing bidding requirements for RA resources, the Commission should focus on getting the slice-of-day framework right such that LSEs contract for sufficient capacity to meet energy needs all hours of the day. LSEs themselves can then make the best decisions for themselves around how to hedge against energy price spikes. The Commission should not adopt uniform bidding requirements on RA resources.

[19] *Id.* at 26-27.

Finally, based upon current must offer rules for CAISO internal resources, it is not clear that a strike price is necessary to ensure reliability. For imports, the CPUC has already adopted rules to ensure that the energy from RA capacity is made available to the market. Internal resources, on the other hand, have a must offer obligation in the CAISO market. This is coupled with mechanisms for market power mitigation for local area resources. The fact that in order to export an internal resource, the resource would have to clear the CAISO market or become uninstructed imbalance energy makes it exceedingly unlikely that a capacity resource inside of the CAISO will not provide energy from their RA capacity in a manner similar to the concerns the Commission expressed with regard to import RA. This is particularly true when coupled with the strengthened withholding rules in place at the Federal Energy Regulatory Commission. Therefore, a mechanism that would require a strike price is directed at the price of energy and not the grid reliability that is the focus of the RA program.

D. The Commission and the CAISO Should Coordinate to Adopt the UCAP Methodology

In the Working Group Report, the CAISO proposes to use UCAP to account for forced outages in the NQC of thermal generators. A UCAP methodology offers several benefits. First, attributing unit specific performance metrics into resources' capacity values rather than including a forced outage percentage in the PRM allows LSEs to assess the reliability of resources when making contracting decisions. By placing the impacts of forced outages and thermal derates on the contracting LSE rather than spreading them across all LSEs, UCAP would prevent a cost shift onto those contracting with more reliable resources. Second, it allows the CAISO to eliminate its Resource Adequacy Availability Incentive Mechanism tool, which has proven to be ineffective at incenting forced outage substitution. Finally, UCAP provides the right incentives for generators to conduct planned maintenance to reduce the chance of forced outages occurring when the system needs the resource. CalCCA generally supports the UCAP concept so long as forced outages are also removed from the PRM.

The CAISO's proposal in the Working Group report uses a Weighted Seasonal Average Availability Factor to calculate forced outages which would assess forced outage rates seasonally during the tightest RA supply conditions. Alternatively, the Commission, in its LOLE Study, used a different methodology to calculate forced outage rates, the Effective Forced Outage Rate of Demand (EFORd) calculation which assesses if units are available when they are "in demand" based on a stochastic simulation of system operations. The Commission and the CAISO should work together to ensure the calculations used to assess forced outage rates are consistent and that the CPUC processes, including setting the PRM and the qualifying capacity values, and the CAISO processes, including must offer obligations and substitution rules, are aligned to account for the UCAP framework. The Commission should also ensure the implementation of UCAP does not have unintended impacts to existing contracts.

III. CONCLUSION

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

Respectfully submitted,

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

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	R.21-10-002

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON THE LOCAL CAPACITY REQUIREMENT (LCR) FINAL WORKING GROUP REPORT AND ENERGY DIVISION'S LOSS OF LOAD EXPECTATION STUDY

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SUMMARY OF RECOMMENDATIONS

- With the exception of the modifications made in D.21-06-029, further ELCC modifications should not be adopted until the slice-of-day framework has been determined;
- The Commission should demonstrate the total NQC of the resources available in the market will cover the megawatts of NQC required under the new PRM;
- CalAdvocates incorrectly states LOLE studies are inappropriate for determining RA requirements and its PRM proposal should be rejected;
- CalCCA agrees with parties that planned outage impacts should not be included in the PRM;
- UCAP can appropriately estimate future resource performance and should be adopted; and
- CalCCA supports PG&E's recommendation for the 2022-2023 TPP to include up to date LCR study criteria.

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 REPLY COMMENTS ON THE LOCAL CAPACITY REQUIREMENT (LCR) FINAL WORKING GROUP REPORT AND ENERGY DIVISION'S LOSS OF LOAD EXPECTATION STUDY

I. INTRODUCTION

The California Community Choice Association (CalCCA)[1] submits these Reply Comments pursuant to the schedule set forth in the *Administrative Law Judge's Ruling Seeking Comments on the Future of Resource Adequacy Working Group Report and the Local Capacity Requirement Working Group Report (Ruling), issued on March 4, 2022*. CalCCA's Reply Comments respond to parties' Opening Comments on both California Community Choice Association and Pacific Gas and Electric Company's (U 39 E) Local Capacity Requirement (LCR) Final Working Group Report[2] (Final Report), and Energy Division Study for Proceeding

[1] California Community Choice Association represents the interests of 23 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, 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, Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

[2] *California Community Choice Association and Pacific Gas and Electric Company's (U 39 E) Local Capacity Requirement (LCR) Final Working Group Report*, Rulemaking (R.) 21-10-002 (Feb 28, 2022).

R.21-10-002, Loss of Load Expectation and Effective Load Carrying Capability Study Results for 2024[3] (LOLE Study).

II. REPLY COMMENTS TO LOLE STUDY COMMENTS

A. With the Exception of the Modifications Made in Decision (D.) 21-06-029, Further Effective Load Carrying Capacity (ELCC) Modifications Should not be Adopted Until the Slice-of-Day Framework has Been Determined

Southern California Edison Company (SCE) suggests the ELCC and Planning Reserve Margin (PRM) results should not be adopted because they require further in-depth stakeholder review and they are not compatible with the slice-of-day framework the California Public Utilities Commission (Commission) seeks to implement by 2024.[4] CalCCA agrees with SCE that the PRM and ELCC will need to be reevaluated pending the adoption of slice-of-day reform. For this reason, the Commission should maintain the existing ELCC methodology and ELCC values for 2023, with the exception of results driven by the modification made in D.21-06-029 that adopted biennial updates and regional wind values beginning in 2023.[5]

Because a slice-of-day proposal is expected to be adopted in the coming year that would necessitate either a move away from ELCCs entirely or a reevaluation of existing ELCCs, the Commission should aim to maintain stability in contracting for the upcoming year by maintaining consistent ELCC values to the extent possible. The only updates made to the ELCCs at this time should be those necessary to comply with D.21-06-029, which adopted biennial ELCC updates and regional wind values beginning in 2023. The LOLE study contemplated

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3 *Energy Division Study for Proceeding R.21-10-002, Loss of Load Expectation and Effective Load Carrying Capability Study Results for 2024*, R.21-10-002 (Feb 18, 2022).

4 *Southern California Edison Company's Opening Comments on Energy Division's Loss of Load Expectation Study and Workshop*, R.21-10-002 (Mar. 14, 2022), at 1-2.

5 *Decision Adopting Local Capacity Obligations for 2022-2024, Flexible Capacity Obligations for 2022, and Refinements to the Resource Adequacy Program*, R.19-11-009 (June 24, 2021) (D.21-06-029), Ordering Paragraphs 14 and 15.

many other modifications to ELCCs including adopting storage and hybrid ELCCs for Resource Adequacy (RA) counting, using a new methodology for allocating diversity benefits, and using different portfolios to represent the expected fleet for 2023 and 2024. Given the comments from numerous parties including CalCCA, both the storage and hybrid assumptions and the methodology for allocating diversity benefits require additional clarification, discussion, and consideration before they can be adopted. Because changes to the ELCC methodology and values would only be in place for potentially one year, the Commission should not make major changes to ELCCs that are not yet well understood by stakeholders and would only be in place for one year.

Before adopting a new PRM, the Commission should first ensure there are enough resources to satisfy the need such that load-serving entities (LSEs) can satisfy their requirements. To accomplish this, the Commission should demonstrate the total Net Qualifying Capacity (NQC) of the resources available in the market will cover the megawatts of NQC required under the new PRM. Available resources could include both existing resources and resources in the Integrated Resource Plan (IRP) that are expected to be built by the time the PRM is modified. This would provide valuable insight into how constrained the market is, or is expected to be, after the completion of new resource build. It is critical to ensure the new PRM establishes a target that is achievable by LSEs; otherwise, the Commission risks being unable to meet a targeted level of reliability with the available RA fleet while simultaneously increasing customer costs through the resulting market power and unavoidable penalties. Before adopting a new PRM, the Commission should ensure there are enough resources available above the requirement to meet the need and commit to re-evaluating the PRM following the outcome of the slice-of-day reform. If the existing resources and the expected resources from the IRP are insufficient to meet the new PRM, then the Commission should institute a transition period that would delay implementing the PRM to provide additional time for planned resources to come online or to consider the need for new resource build in the IRP proceeding. Once sufficient resources have come online to support the updated PRM, the Commission should implement the new PRM. This would ensure that the available RA fleet is capable of meeting the targeted level of reliability used to set the PRM and ensure LSEs are capable of meeting their compliance obligations.

B. CalAdvocates Incorrectly States LOLE Studies are Inappropriate for Determining RA Requirements and its PRM Proposal Should be Rejected

The Public Advocates Office (CalAdvocates) suggests an LOLE study is not appropriate for calculating RA obligations because it would lead to a sense of false precision resulting from the need to make assumptions around resource planning and the nature of system reliability needs.[6] Instead, CalAdvocates proposes the Commission use a 1-in-5 load forecast and a 13 percent PRM to account for reserves and forced outages.[7] CalCCA disagrees with the assertion that LOLE studies are not appropriate for setting a PRM. LOLE studies are critical to inform the amount of resources that need to be procured as RA in order to meet a targeted level of reliability. Foregoing such a study in favor of major modifications proposed by CalAdvocates that have not been properly vetted in this proceeding is not appropriate. While CalAdvocates cautions against LOLE studies due the number of assumptions made, the Commission should take the time through a robust stakeholder process to ensure the assumptions are reasonable rather than abandon a well-established industry practice for establishing a PRM.

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6 *Comments of the Public Advocates Office on the Energy Division Loss of Load Expectation and Effective Load Carrying Capability Study Results for 2024 and the California Energy Commission Qualifying Capacity of Supply-Side Demand Response Working Group Interim Report*, R.21-10-002 (Mar. 14, 2022) (CalAdvocates Comments), at 9-11.

7 CalAdvocates Comments at 11-14.

C. CalCCA Agrees with Parties that Planned Outage Impacts Should not be Included in the PRM

In questions to the LOLE study, Energy Division asked how planned outages should be treated in calculating a PRM. Many parties including CalCCA commented that planned outages on RA resources necessitate substitution to ensure the RA capacity is covered.[8] Parties also indicated planned outages are typically taken in off-peak months when load is low and the capacity is unlikely to be needed.[9] San Diego Gas and Electric Company (SDG&E) suggests, "Planned outages should be included in the LOLE study, causing the respective resource to be unavailable during the planned outage as partial or full outage according to the plans."[10] First, it is not clear how the resource planned outage plans could be determined up front to incorporate into the LOLE study – planned outage assumptions would need to be made. Second, planned outages are optimized such that they are taken when loads are low and the system is not constrained, the California Independent System Operator Corporation (CAISO) approval process ensures that resources are not on planned outage when the CAISO expects they are needed, or they are substituted for such that another resource is available to cover the RA resource taking maintenance. Therefore, CalCCA supports the study's approach of removing planned outages from the PRM determination.

D. UCAP can Appropriately Estimate Future Resource Performance and Should be Adopted

Calpine indicated that it generally does not support adjusting qualifying capacities to reflect forced outages due to concerns around the accuracy of using historical forced outage

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8 CalCCA Comments at 9.

9 *Comments of Pacific Gas and Electric Company (U 39 E) on Energy Division's Loss of Load Expectation Analysis*, R.21-10-002 (Mar. 14, 2022), at 5.

10 *San Diego Gas & Electric Company (U 902 E) Comments on Energy Division LOLE Study,* R.21-10-002 (Mar. 14, 2022), at 3.

performance to reflect future performance.[11] CalCCA disagrees with Calpine's concern that past performance is not a good predictor of future performance and notes that most other resources are valued based on past performance in some manner. If parties are concerned that a Unforced Capacity (UCAP) methodology would not reflect in forced outage rates any major maintenance that occurs to improves the reliability of a resource, the Commission and the CAISO could adopt a methodology that weights recent years more heavily as proposed by the CAISO in its UCAP proposal.[12] While CalCCA supports UCAP in concept, the Commission must ensure it appropriately updates the PRM in tandem by removing forced outages from the PRM. The Commission must also ensure that if it adopts a UCAP framework, it aligns its approach with the CAISO, such that the Commission and CAISO use the same methodology for calculating forced outages and the CAISO updates its RA rules to account for the new UCAP methodology (e.g., removing the Resource Adequacy Availability Incentive Mechanism (RAAIM) and establishing must offer obligation rules to account for UCAP).

III. REPLY COMMENTS TO LCR WORKING GROUP COMMENTS

A. CalCCA Supports PG&E's Recommendation for the 2022-2023 Transmission Planning Process (TPP) to Include up to Date LCR Study Criteria

In comments to the LCR Working Group Report, Pacific Gas and Electric Company (PG&E) indicated that it would be requesting that the CAISO conduct LCR reduction studies using the new local reliability criteria within the 2022-2023 TPP.[13] CalCCA supports this

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[11] *Comments of Calpine Corporation on Administrative Law Judge's Ruling on Loss OF Load Expectation Study and Supply-Side Demand Response Report*, R.21-10-002 (Mar. 14, 2022), at 8.

[12] *See* Future of Resource Adequacy Working Group Report (R.21-10-002), at 56: "To ensure the UCAP provides more up-to-date performance information, the CPUC could place greater weight on the most recent year's performance and less weight on prior periods in determining a resource's UCAP values."

[13] *Opening Comments of Pacific Gas and Electric Company (U 39 E) on the Local Capacity Requirement Working Group Report*, R.21-10-002 (Mar. 14, 2022), at 3.

recommendation as it will better inform CPEs and LSEs of near term and long term LCR needs. It will also allow for a better evaluation of transmission upgrades need to relive local area constraints by aligning the near term and long term LCR studies with the criteria driving the local capacity requirements.

IV. CONCLUSION

For all the foregoing reasons, CalCCA respectfully requests consideration of these Reply Comments.

Respectfully submitted,

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

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING DISTRIBUTING WORKSHOP AGENDA AND PROVIDING QUESTIONS FOR ADDITIONAL POST WORKSHOP COMMENTS

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SUMMARY OF RECOMMENDATIONS

- The overall Provider of Last Resort (POLR) process is not broken; CalCCA agrees with the investor-owned utilities (IOUs) that continuing to provide the POLR a six-month runway to prepare for a return of customers remains reasonable.

- Financial security requirements (FSR) for load-serving entities (LSEs) should be refined to reflect the current market price benchmarks (MPBs) for resource adequacy (RA) and Renewable Portfolio Standard (RPS) products. If the existing FSR is adjusted further to refine the accuracy of the calculation, the Commission must consider the full range of accuracy adjustments proposed by Southern California Edison Company (SCE) and CalCCA.

- The POLR's most urgent role is to provide energy to returning customers. The POLR thus should maintain the existing right to an RA waiver when resources are unavailable at a reasonable price and should receive a deferral of obligations to meet RPS and Integrated Resource Plan (IRP) requirements where circumstances require.

- The POLR should not be required to "hedge" or procure resources in advance of any customer returns. Putting the POLR in the market for these additional resources would only exacerbate resource constraints and increase costs for not only returning LSEs but *all* LSEs.

- To the extent the POLR must advance funds to pay for costs before customer revenues start to cover such costs, the POLR should recover financing cost through balancing account treatment as it does in other circumstances.

- The implementation planning process for new community choice aggregators (CCAs) should be refined to require additional financial projections with standardized assumptions, a milestone plan for implementation, quarterly check-ins with Commission staff to prepare for launch and final financial projection and check-in six months prior to launch.

- Operating CCAs should be subject to a three-tiered reporting rubric with the approach calibrated to the CCA's circumstances.

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

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING DISTRIBUTING WORKSHOP AGENDA AND PROVIDING QUESTIONS FOR ADDITIONAL POST WORKSHOP COMMENTS

The California Community Choice Association[1] (CalCCA) submits these Comments in response to the *Administrative Law Judge's Ruling Distributing Workshop Agenda and Providing Questions for Additional Post Workshop Comments* (Ruling),[2] issued on February 24, 2022.

I. INTRODUCTION

The objective in this proceeding is to implement Senate Bill 520 (SB 520), which established requirements for a POLR -- whether an IOU, another LSE, or a third party. SB 520 rightly directed the California Public Utilities Commission (Commission) to ensure that a POLR is capable of serving its intended role of providing a service to any customer returning to its service without undermining reliability and the state's climate goals or shifting costs to other customers. The tone of the proceeding, however, has been set by a fear of a "Black Swan" event

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1 California Community Choice Association represents the interests of 23 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, 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 *Administrative Law Judge's Ruling Distributing Workshop Agenda and Providing Questions for Additional Post Workshop Comments,* Rulemaking (R.) 21-03-011 (Feb. 24, 2022) (Ruling).

-- an unpredictable or improbable event with potentially severe consequences. As Energy Division Staff explained during the March 7, 2022 workshop:

> If the LSE fails and the POLR is not readily able to secure the resources needed to serve the returning customers, not only will the procurement costs will spike for returning customers, but the capacity shortfall will continue, impacting the cost for everyone. In a worst-case scenario, the conditions could lead to additional LSE failures. The POLR must be able to perform its responsibilities even in the event of large and/or cascading failures and in extreme market conditions, when the resources are not readily available.[3]

CalCCA does not dismiss these concerns; unpredictable and improbable events can and do occur, and SB 520 does require the Commission to address "potentially large and unplanned" returns.[4] But if the Commission is trying to design structures around extreme events, focusing on CCAs is an unreasonably narrow approach. An extreme event can affect both IOU and Electric Service Provider (ESP) customers. Indeed, the 2021 Texas Black Swan Blackout, which was due to several key factors that could not be repeated in California,[5] involved retail electric service providers – not CCAs -- returning customers.[6] In addition, California's closest experience – the 2000-2001 energy crisis – involved IOUs facing out-of-control prices, and the IOUs had to serve the customers and deal with the costs directly driving one IOU into bankruptcy. An unpredictable, extreme event could wreak havoc on all LSEs and their customers, which SB 520 recognizes by requiring the Commission to develop rules for "all LSEs," not just CCAs.

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3 Provider of Last Resort (POLR) Workshop #2, Ruling, Mar. 7, 2022 (POLR Workshop #2 Presentations), at Slide 8.

4 Cal. Pub. Util. Code § 387.

5 Such factors include harsh weather conditions that froze natural gas equipment and caused generator failures and an energy-only market with price caps at $9,000/MWh.

6 *The Timeline and Events of the February 2021 Texas Electric Grid Blackouts*, The University of Texas at Austin Energy Institute, July 2021, at 65: https://energy.utexas.edu/sites/default/files/UTAustin%20%282021%29%20EventsFebruary2021TexasBlackout%2020210714.pdf.

Assuming that these conditions are somehow rooted in the CCA framework ignores the full picture and unfairly disadvantages CCA customers.

Staff's approach also strays from the proceeding's goal by mixing together the current resource constraints in the market with concerns over CCA customer returns. The state's existing resources are without question constrained. But the constraint was not caused by CCAs, but rather a failure of adequate planning for many years. Moreover, the risk that the constraints will drive price spikes exists for a host of reasons independent of CCA financial conditions. Efforts to use the POLR to solve the resource constraint problem are misplaced.

A more reasonable starting place to evaluate POLR procedures and adequacy is a balanced examination of recent, actual experience of customer returns and an evidence-based examination of the actual risks of returns. SCE has real life experience with customer return with the 2021-2022 returns by Western Community Energy and Baldwin Park Resident Owned Utility District. SCE has offered a number of refinements – some of which CalCCA currently supports -- that are relatively modest in comparison with those offered initially by Staff, Pacific Gas & Electric Company (PG&E), and other parties. Attention should be focused on getting a workable return process in place, based on that experience, which can be scaled as needed.

The overall POLR process is not broken. To shore up the existing POLR structure, CalCCA proposes the following measures and looks forward to further collaboration with the Staff and stakeholders to further refine these proposals.

- The overall POLR process is not broken; CalCCA agrees with the IOUs that continuing to provide the POLR a six-month runway to prepare for a return of customers remains reasonable.
- FSRs for LSEs should be refined to reflect the current MPBs for RA and RPS products. If the existing FSR is adjusted further to refine the accuracy of the calculation, the Commission must consider the full range of accuracy adjustments proposed by SCE and CalCCA.

- The POLR's most urgent role is to provide energy to returning customers. The POLR thus should maintain the existing right to an RA waiver when resources are unavailable at a reasonable price and should receive a deferral of obligations to meet RPS and IRP requirements where circumstances require.

- The POLR should not be required to "hedge" or procure resources in advance of any customer returns. Putting the POLR in the market for these additional resources would only exacerbate resource constraints and increase costs for not only returning LSEs but *all* LSEs.

- To the extent the POLR must advance funds to pay for costs before customer revenues start to cover such costs, the POLR should recover financing costs through balancing account treatment as it does in other circumstances.

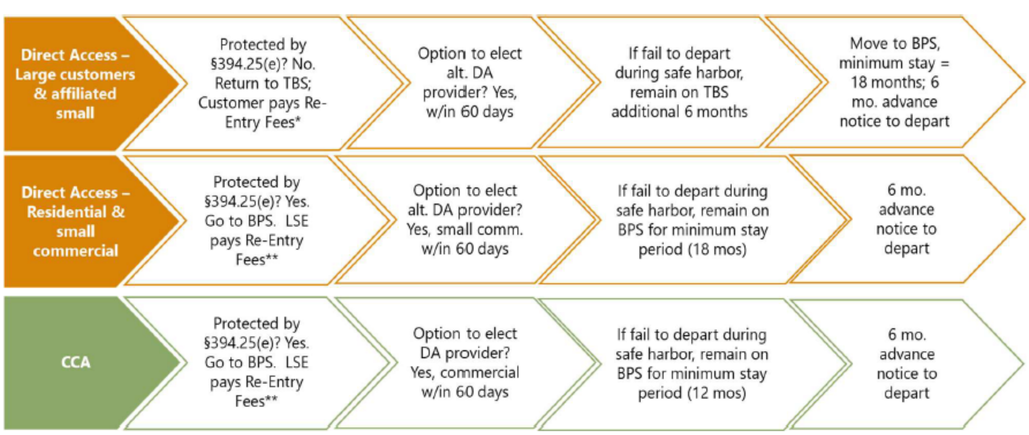
- The implementation planning process for new CCAs should be refined to require additional financial projections with standardized assumptions, a milestone plan for implementation, quarterly check-ins with Commission staff to prepare for launch and final financial projection and check-in six months prior to launch.

- Operating CCAs should be subject to a three-tiered reporting rubric with the approach calibrated to the CCA's circumstances.

II. DEFINITION OF POLR SERVICE

CalCCA does not propose any change in the existing definition of or general process for POLR service. POLR service today can be defined as a service provided by the IOU for a specified period when customers are involuntarily returned to the IOU by their LSE. Today, customers are returned consistent with the process shown in Figure 1 below.

Figure 1: Existing Return Process Presented at the March 7, 2022 Working Group



The "POLR period" for most CCA customers, who do not have Direct Access (DA) options, is six months, beginning on the date the customers are returned. A DA customer with a 60-day safe harbor period for switching ESPs is effectively eight months: the two months of safe harbor plus the six months of additional POLR service.

Two important dynamics define the POLR period for an involuntary return of customers. First, during the six-month period, the POLR must step into the compliance obligations (RPS, RA, and IRP) for the returned customers, a process that is described in Section IV below. Second, the POLR procurement for the returned customers during this period is supported by financial security provided by the returning LSE, which is discussed in Section III below.

While CalCCA proposes changes to these and other dynamics, there is no need to modify the definition or process for an involuntary return of customers to the POLR. The IOUs appear aligned, with no proposals for modification of this process.

III. POLR LIQUIDITY NEEDS

As discussed above, a central goal in this proceeding is ensuring the POLR has the financial capability of meeting its procurement requirements on behalf of the returned customers during the six-month POLR period. Ensuring the POLR is financially capable involves considering two dimensions of the problem: the amount of needed financial security and the timing of this security. Proposals have been offered in this proceeding to address both the amount and timing.

The Ruling attempts to separate these two closely related issues. It seeks comments on "POLR liquidity" with a specific focus on PG&E's proposed insurance pool. The Ruling defers consideration of changes to the existing FSR to a future workshop.[7] POLR liquidity, the PG&E

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[7] Ruling at 2.

insurance pool proposal, and the FSR cannot be discussed in isolation. Because the insurance pool is effectively a substitute for the FSR, the two must be examined in concert. For this reason, CalCCA comments first, on changes that could be made to the FSR to improve the accuracy of the calculation. Second, CalCCA comments on the PG&E pool proposal and offers an alternative to address PG&E's apparent concern around POLR liquidity.

A. FSR Modifications

In the workshop, CalCCA presented several modifications to the cost and revenue estimates used in the FSR calculation that, if adopted, would improve the accuracy of the FSR calculation.[8] Some modifications would increase the required level of FSR posting while others would decrease the required level of FSR posting. SCE and PG&E, likewise, have proposed changes to the calculation of the amount of a security posting.

If the Commission adjusts the FSR calculation, then *all elements* of the FSR should be adjusted to ensure that cost and revenue forecasts are equally informed for all elements. In other words, the Commission should either choose to uniformly improve the accuracy of the FSR or not and should not pick and choose the modifications made to the FSR calculation.

CalCCA discusses below its recommendations for the proposed modifications to the FSR calculation in the context of the FSR formula: *Forecast RA Cost + Forecast RPS Cost + Forecast Energy Cost + Administrative Fee – Forecast Revenue*.

1. Forecast Costs

Three proposals have been presented to modify the calculation of the Forecast RA and RPS Cost component of the FSR.

- CalCCA has agreed with SCE's proposal to update the proxies used for RA price and RPS prices.

[8] POLR Workshop #2 Presentations, at Slides 46-48.

- CalCCA has proposed adjustment of the quantity of RA to which the proxy prices would be applied to reflect the availability of resources in the IOU portfolio to serve the returned customers.

CalCCA addresses these changes below.

a. Rely on Energy Resource Recovery Account (ERRA) Market Price Benchmarks

The current calculation draws the price of RA from Energy Division's most recent RA report. These prices lag behind current market prices, meaning they are out of date when used for this purpose. This lag could be reduced by relying on recent ERRA market price benchmarks as proxies for forecast RA costs. CalCCA has agreed with SCE that this change should be made to improve the accuracy of the FSR calculation.

The RPS price in the FSR calculation should likewise rely on the ERRA MPB for RPS.[9] The 2022 calculated RPS forecast price is $13.70 per megawatt-hour (MWh)[10] and does represent the most current Market Price Benchmark. The prior calculation of this benchmark was adopted by the Commission in Resolution E-5170, authorizing all three IOUs to use the Forecast RPS adder of $14.49/MWh.[11]

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[9] Rule 23 for all three utilities states, "In the absence of a robust index, a forward quote, or durable methodology for regularly estimating the value of a Renewable Energy Credit (REC), [IOU] will use the $10/MWh REC value adopted by the Commission in D.16-05-006 as an estimate of the incremental cost of satisfying the Renewable Portfolio Standard (RPS) requirement for the involuntarily returned CCA load." Since D.16-05-006, the Commission has issued annually a PCIA MPB that has been used as a more robust methodology.

[10] *See* November 1, 2021 Energy Division values for the Power Charge Indifference Adjustment (PCIA) Forecast and True Up. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/community-choice-aggregation-and-direct-access/calculation-of-the-market-price-benchmarks-20212022.docx.

[11] The Energy Division PCIA Forecast and True Up November 2, 2020 https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/community-choice-aggregation-and-direct-access/2020-calculation-of-the-market-price-benchmarks.pdf.

b. Account for Resources Readily Available to the POLR

While using a more current benchmark may provide for a more accurate calculation, the calculation should also deduct costs for any resources the returned customers will pay for through a separate rate mechanism. Cost Allocation Mechanism (CAM) resources provide RA for all customers through a charge recovered in distribution rates. Whether a customer is served by another LSE or the IOU, the customer will pay for and receive its proportional share of RA associated with the CAM resources. The cost should not be duplicated through the FSR. To avoid duplication, CAM RA quantities should be netted out of the RA quantity priced by the calculation; alternatively, the IOU could price this quantity of RA at zero for the FSR calculation.

2. Forecast Revenues

During the March 7, 2022 workshop, CalCCA presented a number of additional changes to the FSR calculation that could improve the ability of the FSR to more accurately depict costs and revenues resulting in a better FSR calculation.

a. Forecast Generation Rate Revenue

CalCCA recommends several modifications to the calculation of forecasted revenue offset to costs to ensure the FSR calculation correctly estimates anticipated revenues resulting from customer returns. <u>First</u>, today the revenue offset of the FSR is calculated using the IOU's *system* average rates. The rate thus reflects the IOU's blend of customer classes. A CCA's mix of customers, however, may vary significantly from the IOU's mix; using the system average thus could materially overstate or understate the expected revenues. It is generally the case for all three IOUs that the average rates within the CPUC defined rate classes are; residential > commercial and industrial > agricultural > street lighting. If a CCA serves a higher proportion of residential customers than the IOU system average, then the returning load would be expected to generate higher revenues than that of the IOU system average rate. Consequently, CalCCA recommends the Commission reflect average customer rates *by class* for each CCA to better reflect anticipated revenues for any individual CCA return.

Second, although IOU generation rates are seasonally differentiated, the FSR revenue offset does not reflect that seasonality instead using an annual average. While the forward Intercontinental Exchange (ICE) energy price forecast component of the FSR/re-entry fee will reflect the season differences in costs of energy, the use of a system annual average rate will not. The result then is an estimation of generation rate revenues in the summer that is lower than what rates will recover and higher in the winter. At the same time, the ICE cost estimate is reflecting the expected costs for a seasonally representative period which will create an FSR/re-entry fee calculation that is artificially high in the summer and artificially low in the winter. Therefore, CalCCA recommends the Commission seasonally differentiate average generation rate revenues to match seasonal differentiation of forecast energy costs. Third, the FSR calculation should consider approved IOU rate changes that will take effect during the FSR posting period. For example, the November 10, 2021 advice letter filed by the IOUs should reflect Commission authorized rate changes from a general rate case or ERRA case to bundled rates that will be in effect the first six months of the next year to reduce the likelihood of a discrepancy between a posted FSR and a calculated reentry fee. This should occur in the May FSR update as well.

b. Power Charge Indifference Adjustment (PCIA) Netting

SCE has proposed a reduction in the PCIA revenue credit that would be applied in calculating FSR; CalCCA in response has pointed out that the PCIA component should not be adjusted unless other PCIA-related influences on the formula are modified. The PCIA is a complex instrument. SCE has proposed that the credit of generation rate revenues from returning customers be netted against the PCIA component that they will pay as a bundled load customer so that the generation revenues reflect incremental revenues. Such an adjustment requires further vetting to ensure that the interaction of PCIA, bundled rates, and ERRA true-ups work in concert and do not shift costs. In addition, if changes are to be made to the FSR to reflect the PCIA net revenues, then other changes should also be considered that will better reflect the costs and revenues of customers receiving POLR service.

B. Balancing Accounts With Interests Should be Used to Address PG&E's Liquidity Concern Rather Than PG&E's Pool Proposal

PG&E proposes to replace the current FSR process with a sort of insurance or credit "pool" to address liquidity. This proposal increases the amount of security that would be required to have two months of liquidity readily at hand. PG&E suggests that each CCA would contribute to the pool a forecast two months of POLR service[12] *without* offsetting anticipated revenues from the returned customers. While risk pooling in theory could lower the overall cost of security, PG&E's proposal does not achieve such cost reductions. CalCCA calculates the amount of security PG&E proposes at roughly $1.4 billion pool for all CCAs – an outsized impact driven primarily by PG&E's proposal to remove the revenue offset from the FSR calculation.[13]

Beyond the magnitude of impact, PG&E's proposal suffers from other problems. PG&E appears to assume that CCAs would contribute to the pool cash or some other instrument, such as a letter of credit. While this may be one way to prevent a cost shift to bundled customers, it has the potential to shift costs among CCAs instead. As mentioned by Peninsula Clean Energy during the March 7, 2022 Workshop, the mechanism would allow the POLR to take cash or a financial instrument from one LSE to support the return of customers from another LSE. Allowing the POLR to draw upon a pool to address the returning customers which may include

[12] March 7, 2022 POLR Workshop Presentation, at Slide 38.
[13] *Id.,* at Slide 45.

CCAs with returning customers and CCAs who are not returning customers may address the shifting of costs from CCA customers and bundled load customers but it does not address cost shifting among CCA customers being served by different CCAs.

Further, PG&E's pool proposal would only apply to CCAs, not ESPs. Parties at the workshop suggested that ESP customers should not be subject to PG&E's pool proposal or other changes to enhance liquidity because they can elect to go to another ESP in the event of a failure of their existing ESP. As discussed above, however, if the Commission's worry is a Black Swan type of event, neither ESPs nor IOUs will be exempt from the impacts. If prices were driven beyond a sustainable level, ESPs could choose to return customers to the IOUs rather than continuing to procure at the high prices. For these reasons, ESPs should be included in any adopted modifications to the FSR.

If PG&E's concern is "liquidity" – having funds available when needed – CalCCA submits that there is a less expensive approach to address liquidity than what PG&E has proposed. The Commission could, as it has done for years, use a balancing account with financing charges for the required liquidity. The benefit of this approach is that costs to provide liquidity are incurred only if customers are actually returned to the IOU.

IV. RESOURCE AVAILABILITY

A. The POLR Should Assume Energy, RA, RPS, and IRP Compliance Obligations for Returned Customers During the POLR Period

As the POLR assumes responsibility for the returned customers for the future, it must take on all procurement and compliance obligations for those customers. CalCCA proposes that in addition to purchasing energy from the CAISO for these customers, the POLR should assume RA, RPS, and IRP mandate obligations effective upon the date of the customer return, although actual procurement may be delayed. To avoid speculative and unnecessary costs, however, the POLR should not be required to procure any product in advance of a notice of customer return.

The POLR's most urgent role is to provide energy to returning customers. Therefore, during the six months that returning customers are under POLR service, the POLR should procure energy from the CAISO for these customers. This obligation becomes effective upon the date of customer return.

Meeting compliance requirements should be approached more cautiously, considering market conditions and compliance timelines. Compliance requirements for RA, RPS, and IRP procurement mandates should be addressed as follows:

- Depending on the timing of customer return, the POLR may not be able to procure RA for those customers given RA showings are due 45 days prior to the month. The POLR should thus maintain the existing right to an RA waiver when compliance dates have passed or resources are unavailable at a reasonable price.

- While RPS procurement is critical in the long run, it does not wear the same urgency as energy and RA. Thus, while the POLR will assume the obligations upon customer return, it should procure any needed resources in a manner that avoids market power exercise or unnecessary costs. If a return falls close to an upcoming compliance date, the POLR should receive a temporary deferral of the obligation.

- Compliance with IRP mandates, like RPS, may be a longer-term concern and present more complication. The IRP mandates are designed to get new resources built, and if the returning LSE has accomplished some or all of its obligations, the POLR should not duplicate these costs. Its obligations should be limited to fulfilling any shortfalls experienced by the returning LSE and a going forward obligation. Again, the POLR and the Commission should be mindful of market conditions in considering the timing of any "catch up" procurement to avoid unnecessary costs. If necessary, the POLR should receive a deferral of its obligation to the extent the Commission deems reasonable considering current market conditions.

The POLR should not be required to "hedge" or procure resources in advance of any customer returns. First, it would be nearly impossible for the POLR to conduct effective hedging given the speculative nature of customer returns. Asking customers to pay the costs of ineffective hedges to protect against customer returns that may or may not happen is unreasonable. Second, putting the POLR in the market for these additional resources in advance would only exacerbate resource constraints and increase costs for not only customers of returning LSEs but customers of *all* LSEs. Finally, if resources are scarce, and the POLR successfully procures remaining resources in the market, other LSEs could find themselves without sufficient supply to meet requirements, facing penalties. Imposing penalties on deficient LSEs for a deficiency caused by the POLR when the deficiency was caused by the POLR unnecessarily increases costs to any entity required to pay for advance procurement. All procurement and compliance obligations should remain, as they do today, with LSEs actively providing services to their customers.

B. LSE Contract Assignment to POLR

The Ruling asks parties to consider if the POLR should be required to assume resource contracts from the returning LSE through a "right of first refusal" (ROFR) provision within LSE contracts. During the workshop, the Solar Energy Industries Association and the Large-scale Solar Association indicated mandatory contract assignment from the LSE to the POLR would be beneficial, and the SBUA suggested voluntary assignment. However, as discussed in CalCCA's workshop presentation, significant policy and legal concerns arise should the Commission require CCAs or ESPs to provide in their contracts for the assignment of the contract to the POLR in the event of its deregistration.

1. Policy Concerns With Contract Assignability

CalCCA has identified policy or market issues raised by contract assignment to the POLR. First, it is unclear how such a POLR ROFR requirement would affect a generator's or market participant's willingness to transact with the POLR. Second, even if parties were interested in such transactions, all such conditions come at a cost. In this case, the cost would be limited to the CCA or ESP; the IOU and its customers would be unaffected. Third, there are numerous existing contracts that do not contain these provisions with some of those being long-term contracts to meet RPS requirements. To implement a new requirement would potentially mean the re-negotiation of contracts whose terms and conditions may have been set years prior. Any such renegotiation will result in one party or the other seeking additional changes to a contract entered in good faith drawing into question the value of long-term contracting in California's complicated energy space. Fourth, the provision would substantially complicate portfolio management. Serious questions arise whether and under what terms and conditions the CCA could resell the output under the contract if it is burdened by a POLR ROFR. CalCCA does not support a requirement for the POLR to assume resource contracts from the returning LSE through a "right of first refusal" or as a mandatory assignment provision within LSE contracts.

2. Legal Concerns With Contract Assignability

CalCCA has identified serious legal questions raised by a POLR ROFR in the context of bankruptcy, where the provision would have its greatest value. A POLR ROFR provision likely would be unenforceable in a bankruptcy since it would undermine the court's jurisdiction in distributing the estate's assets or reorganizing its obligations. The Supremacy Clause of the Constitution mandates that federal laws, such as those concerning bankruptcy, "shall be the supreme Law of the Land; . . . [the] Laws of any State to the Contrary notwithstanding."[14] "Congress' intent to supersede state law altogether may be found from a "'scheme of federal regulation . . . so pervasive as to make reasonable the inference that Congress left no room for the States to supplement it,' because 'the Act of Congress may touch a field in which the federal

[14] U.S. Const., art. VI, cl. 2.

interest is so dominant that the federal system will be assumed to preclude enforcement of state laws on the same subject." [15]

In describing preemption in the context of federal bankruptcy law, the Ninth Circuit has stated that:

> There can be no doubt that federal bankruptcy law is 'pervasive' and involves a federal interest 'so dominant' as to 'preclude enforcement of state laws on the same subject'--much like many other areas of congressional power listed in Article I, Section 8, of the Constitution, such as patents, copyrights, currency, national defense and immigration. The Bankruptcy Clause, which grants Congress the power to make bankruptcy laws, U.S. Const. art. I, § 8, cl. 4, stresses that such rules must be 'uniform.' Bankruptcy law occupies a full title of the United States Code. It provides a comprehensive system of rights, obligations and procedures, as well as a complex administrative machinery that includes a special system of federal courts and United States Trustees. [16]

A POLR ROFR likely would be preempted under this scheme as an *ipso facto* provision. The Bankruptcy Code makes a provision terminating or modifying an executory contract upon the commencement of a bankruptcy case generally inoperative:

> Notwithstanding a provision in an executory contract or unexpired lease, or in applicable law, an executory contract[17] or unexpired lease of the debtor may not be terminated or modified, and any right or obligation under such contract or lease may not be terminated or modified at any time after the commencement of the case solely because of a provision in such contract or lease that is conditioned on …the commencement of a case under this title ….[18]

The reasoning underlying this rule goes to the very heart of bankruptcy's purpose. Complementary sections of the Bankruptcy Code empower a debtor in bankruptcy, or the assigned trustee, to "assume," "assume and assign" or "reject" contracts. 11 U.S.C. § 365(a) &

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15 *Pacific Gas & Electric Co. v. State Energy Resources Conservation & Development Commission*, 461 U.S. 190, 203-04 (1983) (internal citations omitted).

16 *Sherwood Partners, Inc., v. Lycos Inc.*, 394 F.3d 1198, 1201 (9th Cir. 2005) (internal citations omitted).

18 11 U.S.C. § 365(e)(1).

(c). The power to assume, and to assume and assign, valuable contracts is one of the principal benefits of a bankruptcy filing. As the Ninth Circuit court of Appeal explained:

> By invalidating such [*ipso facto*] clauses, § 365(e)(1) promotes the rehabilitation of the debtor by enabling the bankruptcy trustee to assume (and thus continue in force) beneficial contracts that otherwise would have terminated automatically or would have been terminated by the other contracting party. See H.R. Rep. No. 95-595, at 348-49, reprinted in 1978 U.S.C.C.A.N. 5963, 6304-05 (noting that enforcement of ipso facto clauses "frequently hampers rehabilitation efforts"). In short, the purpose of § 365(e)(1) is to protect the debtor from the enforcement of unfavorable insolvency-triggered clauses in executory contracts.[19]

A POLR ROFR thus faces strong legal headwinds. While courts have found in some cases that the Bankruptcy Code is not preempted by a particular state law, those rulings typically conclude that there is no conflict between the state law and the Bankruptcy Code, either because both are capable of being performed or because the *ipso facto* prohibition is not triggered.[20]

V. RISK MANAGEMENT AND FINANCIAL MONITORING

Customer return by an LSE should not come as a surprise to the Commission or the POLR. Improving the ability of the Commission and POLR to anticipate customer returns, to the extent reasonably possible, is a reasonable aim. Any improvements, however, must consider each CCA's position (*e.g.*, new/existing, credit-rated/not rated) and, critically, respect the authority of

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[19] *Spieker Props., L.P. v. MFM The SPFC Liquidating Trust (In re Southern Pac. Funding Corp.)*, 268 F.3d 712, 715-716, (9th Cir. 2001). *See also In re Peaches Records and Tapes, Inc.*, 51 B.R. 583, 587, n.6 (B.A.P. 9th Cir. 1985) (Section 365(e)(1) makes ipso facto clauses which result in a breach solely due to a bankruptcy filing of a party unenforceable subject to certain exceptions); *In re Eastman Kodak, In re Eastman Kodak Co.*, 495 B.R. 618, 623 (Bankr. S.D.N.Y. 2013) ("Section 365 thus advances one of the Code's central purposes, the maximization of the value of the bankruptcy estate for the benefit of creditors.") (internal citations omitted); *In re Enron Corp.*, 306 B.R. 465, 473 (S.D.N.Y. 2004).

[20] *See, e.g., Northwest Wholesale, Inc. v. Pac Organic Fruit, LLC*, 357 P.3d 650 (2015) (holding that Wash. Rev. Code § 25.15.130(1)(d)(ii), which provided for automatic disassociation of LLC members upon a bankruptcy filing, was not preempted by the Bankruptcy Code because the partnership contract was not executory); *Robinson v. Michigan Consolidated Gas Co., Inc.* 918 F.2d 579 (6th Cir. 1990) (Detroit utility termination procedures do not conflict with Bankruptcy Code Section 366 and therefore are not preempted).

local governing boards over CCA financial oversight. With these thoughts in mind, CalCCA recommends possible solutions for both new and existing CCAs.

CalCCA continues to work with CCAs to provide publicly available information concerning their financial status and operating policies (*e.g.*, risk management) readily accessible through a portal on the CalCCA website. The financial information accessible through this portal includes data points necessary to calculate days liquidity on hand, data points necessary to calculate debt ratio, risk management policies, and ratemaking policies and changes. This information captures several interacting factors that contribute to the financial health of an LSE. This initiative should improve the Commission's access to CCA information, which today requires combing through each CCA's websites and meeting minutes. Further, the organization is developing best practices guidance for all members expected to be completed mid-year.

Beyond these initiatives, CalCCA offers recommendations to address information access for new and existing CCAs. First, CalCCA recommends the Commission enhance the implementation planning process to ensure the Commission has predictable, standardized information on a timely basis before a new CCA launches. To do this, the Commission should:

- Require new LSEs to submit a Feasibility Study and a pro forma financial statement with the Implementation Plan;
- Establish annual assumptions to be included in the pro forma financial statement submitted with the Implementation Plan;
- Establish milestones for critical implementation action and review progress in the quarterly check-in with Commission staff; and
- Require new LSEs to update its pro forma financial statement six months prior to launch for review with the Commission and presentation to the CCA's governing board.

These requirements would apply to *newly forming* CCAs only, not existing CCAs expanding their service territories.

Second, CalCCA proposes a tiered approach for financial monitoring of existing LSEs. The approach recognizes that no single metric can provide a full picture of an LSE's financial condition. Financial health for CCAs is a function of liquidity, debt, ratesetting policies, and risk management. For example, a lower Days Liquidity on Hand (DLOH) could be offset by a recent material rate increase.

Akin to SCE's proposal at the March 7, 2022 workshop, the approach would require different levels of financial monitoring depending on the LSEs' financial position. The tiers would be structured as follows:

Tier 1: LSE has an investment grade credit rating: No financial monitoring required recognizing that the LSE's financial health is under watch by a ratings agency, which examines a range of financial indicators;

Tier 2: LSE does not have an investment grade credit rating: DLOH reported periodically to the CPUC confidentially; and

Tier 3: LSE's DLOH dips below a designated threshold: LSE consults with Energy Division Staff.

This structure is designed to facilitate conversations between the Commission and LSEs facing challenges to provide some foresight into potential customer returns.

The Commission should ensure a durable approach such that all entities are evaluated for risk similarly and appropriately. Therefore, CalCCA's proposal for financial monitoring would apply to both CCAs and ESPs. This should also include the IOUs if in the future a non-IOU serves as POLR.

VI. CONCLUSION

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

Respectfully submitted,

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