APRIL FILINGS

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

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

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SUMMARY OF RECOMMENDATIONS

- The Commission should implement a slice-of-day (SOD) framework for the 2025 compliance year at the earliest, given party comments that demonstrate significant additional work is required;
- The current requirements and penalty structure should apply during a test year;
- Parties overstate the complexity of hourly obligation and resource trading; these enhancements should be made to the 24-hour slice proposal such that they are in place for the first compliance year;
- While the storage charging requirement may need to be further evaluated for long-duration storage in the long term, charging requirements should be in place for all storage resources at this time;
- If the 24-hour slice proposal is not adopted, the Commission must address how to account for energy sufficiency;
- CalAdvocates' arguments in favor of hedging requirements are cost-based rather than reliability-based, do not acknowledge hedging practices already in place, and should not be adopted;
- The Commission should coordinate with the CAISO to adopt a UCAP framework, as parties' concerns that UCAP will not achieve the desired maintenance incentives are misguided;
- Multi-year system and flexible RA requirements should be considered in a subsequent proceeding when the full impacts of such change can be examined; and
- The Commission should not adopt CalAdvocates proposed change to the PRM.

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I. INTRODUCTION

The California Community Choice Association[1] (CalCCA) 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*[2] (Ruling), issued on March 4, 2022.

In summary, CalCCA offers the following recommendations in response to parties' Opening Comments:

- The Commission should implement a slice-of-day (SOD) framework for the 2025 compliance year at the earliest, given party comments that demonstrate significant additional work is required;

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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 Seeking Comments on the Future of Resource Adequacy Working Group Report and the Local Capacity Requirement Working Group Report*, R.21-10-002 (Mar. 4, 2022).

- The current requirements and penalty structure should apply during a test year;
- Parties overstate the complexity of hourly obligation and resource trading; these enhancements should be made to the 24-hour slice proposal such that they are in place for the first compliance year;
- While the storage charging requirement may need to be further evaluated for long-duration storage in the long term, charging requirements should be in place for all storage resources at this time;
- If the 24-hour slice proposal is not adopted, the California Public Utilities Commission (Commission) must address how to account for energy sufficiency;
- The Public Advocates Office's (CalAdvocates') arguments in favor of hedging requirements are cost-based rather than reliability-based, do not acknowledge hedging practices already in place, and should not be adopted;
- The Commission should coordinate with the California Independent System Operator Corporation (CAISO) to adopt an unforced capacity (UCAP) framework, as parties' concerns that UCAP will not achieve the desired maintenance incentives are misguided;
- Multi-year system and flexible Resource Adequacy (RA) requirements should be considered in a subsequent proceeding when the full impacts of such change can be examined; and
- The Commission should not adopt CalAdvocates proposed change to the Planning Reserve Margin (PRM).

II. THE COMMISSION SHOULD IMPLEMENT A SOD FRAMEWORK FOR THE 2025 COMPLIANCE YEAR AT THE EARLIEST, GIVEN PARTY COMMENTS THAT DEMONSTRATE SIGNIFICANT ADDITIONAL WORK IS REQUIRED

In Opening Comments, parties provided a substantial list of open issues that need to be developed and milestones that need to be reached in order to implement a SOD framework. These include, among others, enhancing the transactability of the 24-hour slice proposal by allowing hourly obligation and resource trading, finalizing hourly profiles for wind and solar counting, vetting a new loss of load expectation (LOLE) study and resulting PRM, and modifying the CAISO tariffs and systems to align with the new framework. CalCCA agrees that there are a number of issues that need to be worked out prior to the Commission making a final decision. The Commission should allow the time necessary to fully consider and develop these open issues to ensure a reliable, cost-effective, and transactable SOD framework is implemented.

Notably, the CAISO indicates in its comments that it will be difficult for it to conduct an initiative implementable by RA-year 2024. The CAISO further describes four topics it would need to consider within an initiative to align its processes with a SOD framework, including:

1. Whether the CAISO should implement a program where both capacity and energy are considered, but interaction with the CAISO is simplified;
2. Processes for the CAISO to evaluate the energy sufficiency to meet demand and battery charging needs;
3. Structure and data needed to validate capacity and energy showings; and
4. Potential changes to CAISO processes and rules such as outage and substitution requirements and backstop cost allocation.[3]

The CAISO is a critical partner with the Commission in operating California's RA program. Without the ability of the CAISO to implement a compatible framework, the benefits of a SOD framework at the Commission will be diminished. The Commission should allow the necessary time for the CAISO to run its stakeholder process to support the coordinated development of SOD reform with CAISO rule changes.

For these reasons, the Commission should not adopt a SOD framework any earlier than compliance year 2025 to allow the Commission, the CAISO, and parties time to work out open issues and to allow the CAISO time to conduct its stakeholder process. The Commission could issue a decision in Summer 2022 directing parties on which SOD proposal to move forward with (24-hour slice or two-slice), but this decision should not direct implementation any sooner than for compliance year 2025.

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[3] *Opening Comments on the Future of Resource Adequacy Working Group Report of the California Independent System Operator Corporation*, R.21-10-002 (Mar. 24, 2022) (CAISO Comments), at 6-7.

III. THE CURRENT REQUIREMENTS AND PENALTY STRUCTURE SHOULD APPLY DURING A TEST YEAR

Several parties suggest the Commission adopt a test year before fully implementing the 24-hour slice framework. During the test year, load-serving entities (LSEs) would submit non-binding hourly showings to allow the Commission and LSEs to test and evaluate how the showings and validation process works prior to the first compliance year. A test year would be beneficial in that it would allow the Commission and LSEs to work out any issues identified related to showings and validation before the first compliance year. It would also allow additional time for the Commission and parties to work out the many other open issues identified with enough time for planning and procurement to take place before the first compliance year. A 2024 test year and 2025 compliance year would balance the significant work that needs to be accomplished before the framework is ready for implementation and the urgent need for RA reform.

Pacific Gas and Electric Company (PG&E) and the Natural Resources Defense Council (NRDC) suggest that if the Commission uses a test year, the Commission could assess compliance on both the gross and net peak hours during the test year or during a year of "partial implementation."[4] The Commission should not adopt this recommendation. A test year should be just that: a year to test and evaluate the structure as contemplated and adjust if necessary. This test should not change the RA rules otherwise in place, which at present are a system peak load test with maximum cumulative capacity (MCC) buckets to help ensure that resources are available to meet all other hours. The Commission must continue to apply the current rules and requirements and must not institute a net load peak measure. Doing so would effectively

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4 *Comments of Pacific Gas and Electric Company (U 39 E) on the RA Reform Working Group Report*, R.21-10-002 (Mar. 24, 2022) (PG&E Comments), at 1; and *Comments of the Natural Resources Defense Council on the Future of Resource Adequacy Working Group Report*, R.21-10-002 (Mar. 24, 2022), at 6.

implement, in part, the two-slice proposal for an interim year while knowing that the structure will change yet again the following year. Changing RA requirements in a significant fashion in such short order will make contracting for RA resources difficult. For these reasons, the Commission should use a test year to evaluate while continuing with current RA rules.

IV. PARTIES OVERSTATE THE COMPLEXITY OF HOURLY OBLIGATION AND RESOURCE TRADING; THESE ENHANCEMENTS SHOULD BE MADE TO THE 24-HOUR SLICE PROPOSAL SUCH THAT THEY ARE IN PLACE FOR THE FIRST COMPLIANCE YEAR

In Opening Comments, CalCCA expressed support for the 24-hour slice framework contingent on hourly trading of obligations and resources.[5] Hourly transactability is a critical component of a 24-hour slice framework, as it would enable all LSEs to shape their resources and load to meet their obligations without creating artificial market scarcity or necessitating costly over-procurement. Without hourly transactability, the 24-hour slice framework would drive up customer costs and potentially result in the need to hold on to carbon-emitting resources that are not needed if the RA fleet could be used more efficiently through hourly trading. The minor increases in complexity are well worth the benefits of a cost-effective RA program with transactable RA products.

Some parties support considering hourly obligation and resource trading for future adoption after the initial implementation of SOD.[6] If hourly trading is not allowed beginning with the first SOD compliance year, the Commission risks significant market disruption, increased customer costs, and LSEs being non-compliant despite their best efforts. In addition, there is potential to penalize an individual LSE while the sum of all RA showings meet the total

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[5] *California Community Choice Association's Comments on Administrative Law Judge's Ruling Seeking Comments on the Future of Resource Adequacy Working Group Report*, R.21-10-002 (Mar. 24, 2022), at 4-11.

[6] California Efficiency + Demand Management Council, California Energy Storage Alliance, Green Power Institute, and Solar Energy Industries Association and the Large-scale Solar Association.

system need when the individual LSE cannot meet an hour or sub-set of hours due to the lack of ability to trade to meet those hourly requirements. In sum, in order to prevent "leaning" the inability to trade will potentially ignore diversity. While the 24-hour slice proposal has the benefit of ensuring all LSEs bring enough capacity to meet their hourly needs without leaning on the system or other LSEs, this cannot be accomplished at the expense of non-investor-owned utility (IOU) LSEs being subject to artificially scarce RA supply while the IOU LSEs being unnecessarily long. Section 380 requires the RA program to "[m]aximize the ability of community choice aggregators (CCAs) to determine the generation resources used to serve their customers."[7] Subjecting non-IOU LSEs (CCAs) to procuring artificially scarce RA supply due to the inability to transact to meet their obligations conflicts with a fundamental objective of the RA program. Therefore, the 24-hour slice proposal should be implemented with hourly resource and RA obligation trading beginning with the initial compliance year.

Other parties express concern about the perceived complexity hourly trading would add to the 24-hour slice framework.[8] These concerns overstate the complexity of hourly obligation and resource trading. Currently, resources can sell portions of its capacity to multiple LSEs (*e.g.,* 70 percent of its capacity to LSE 1 and 30 percent of its capacity to LSE 2). The Commission validates showings to ensure no portions of resources' capacity are sold to multiple LSEs. This would continue to be allowed under the 24-hour slice proposal. Hourly transactions of resources and obligations can and should also be allowed to ensure LSEs can comply in each hour. The Commission should similarly evaluate hourly transactions to ensure no capacity is double-counted. While this adds some additional complexity for LSEs who would need to transact these

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7 Public Utilities Code § 380(b)(5).

8 California Environmental Justice Alliance (CEJA) and the Union of Concerned Scientists (UCS), and California Large Energy Consumers Association (CLECA).

hourly products, LSEs who would be doing these transactions have indicated that is not only worth the additional complexity, but also a critical component for the 24-hour slice proposal to be workable.

Indeed, moving to hourly is akin to the current RA system. That is, today there are monthly RA requirements. Parties transact individual months and are not restricted to purchasing in time frames longer than the compliance obligation. While parties may purchase multiple months to multiple years, they are not obligated to do so. Rather, an LSE can show a resource for an individual month provided the resource also provides a supply plan. With an hourly requirement, it is not logical to require LSEs to procure more than an individual hour as that is the compliance obligation.

V. WHILE THE STORAGE CHARGING REQUIREMENT MAY NEED TO BE FURTHER EVALUATED FOR LONG-DURATION STORAGE IN THE LONG TERM, CHARGING REQUIREMENTS SHOULD BE IN PLACE FOR ALL STORAGE RESOURCES AT THIS TIME

Form Energy, Inc., requests that if Southern California Edison Company's (SCE's) 24-hour slice proposal is adopted, any storage device capable of output for a duration of 12 hours or more be exempt from the charging sufficiency testing recommended in the SCE proposal.[9] The use of storage with a discharge period of 12 hours or multiple days is very unique and will likely ultimately require further evaluation of the reliability it can provide including how charge energy is made available and assured to be available in a program like RA. The use of such a device to provide RA reliability, however, should not be exempted from the evaluation of charge energy in the near term. Doing so could result in paper compliance without sufficient energy to discharge the resource to meet reliability needs.

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[9] *Comments of Form Energy, Inc. on the Future of Resource Adequacy Working Group Report*, R.21-10-002 (Mar. 24, 2022), at 3-4.

Longer-term, CalCCA agrees that the resource may not charge during the peak load day in any hour relying instead on charging that occurred days or even weeks prior. Such a complication will ultimately require further evaluation to determine how the RA program should assess the efficacy of such facilities. In the near term, with very few of such resources interconnected or in the development stages, it is not appropriate to provide a waiver that could compromise the RA program while a longer-term evaluation is being performed and modifications made to the RA program to account for the unique characteristics of this type of resource.

VI. IF THE 24-HOUR SLICE PROPOSAL IS NOT ADOPTED, THE COMMISSION MUST ADDRESS HOW TO ACCOUNT FOR ENERGY SUFFICIENCY

Parties take varying positions on the use or retirement of MCC buckets. CEJA and UCS claim that under either model, the MCC buckets should be retired.[10] CalAdvocates, on the other hand, recommends retaining MCC buckets regardless of which model the Commission chooses.[11] The CAISO appears to take a middle ground, dependent upon circumstances, noting that the actual RA fleet made available in any month may differ from the fleet used to create Effective Load Carrying Capacity (ELCC) values. Therefore, the CAISO suggests that the availability of energy from the RA fleet may not be assured. This may necessitate the use of MCC buckets so as not to over-rely on use-limited resources under Gridwell Consulting's (Gridwell) two-slice proposal. CalCCA agrees with the CAISO with regard to the Gridwell two-slice proposal in that the potential differences between the RA pool available in any month and the resources used to develop ELCC may not provide enough confidence that the system will be energy sufficient in all hours without the use of MCC buckets.

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10 *California Environmental Justice Alliance and Union of Concerned Scientists Opening Comments on the Future of Resource Adequacy Working Group Report*, R.21-10-002 (Mar. 24, 2022), at 11-12.

11 *Comments of the Public Advocates Office on the Future of Resource Adequacy Working Group Report,* R.21-10-002 (Mar. 24, 2022) (CalAdvocates Comments), at 16-17.

With regard to SCE's 24-hour slice proposal, where use limitations are accounted for in the resource counting rules (*i.e.*, limiting how many hours in a day the resource can be counted upon), limitations on days of availability need to be addressed. For demand response, this is accomplished through a standard in which demand response resources must be available for four consecutive hours over three consecutive days.[12] Given that peak loads do not happen in every day of the month, a system allowing for certain resources to not be available on every day is a reasonable outcome. Determining the minimum number of days a resource must be available should be evaluated under the LOLE study to ensure that the appropriate level of reliability from such resources is being provided and a maximum amount of resources that an LSE could claim that are available for the minimum number of days is appropriate. In short, the Gridwell model will likely continue to require an MCC bucket methodology while the SCE proposal does not. Both models would likely require a limitation on the number of resources that are not available for the hours shown for every day of the month.

VII. CALADVOCATES' ARGUMENTS IN FAVOR OF HEDGING REQUIREMENTS ARE COST-BASED RATHER THAN RELIABILITY-BASED, DO NOT ACKNOWLEDGE HEDGING PRACTICES ALREADY IN PLACE, AND SHOULD NOT BE ADOPTED

CalAdvocates supports the implementation of a mandatory hedging program through the RA mechanism. While CalAdvocates states:

> "There is the potential for numerous ratepayer and LSE operational benefits associated with hedging tools like the hedging proposals in the Slice of Day Report and the use of tolling agreements; tools that can be developed and applied through the RA program,"[13]

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[12] Decision (D.) 11-06-022, *Decision Adopting Local Procurement Obligations for 2012 and Further Reining the Resource Adequacy Program*, R.09-10-032 (June 23, 2011).

[13] CalAdvocates Comments at 10.

none of the six plus pages CalAdvocates dedicates to the topic describe the "operational benefits" with regard to increased grid reliability from resource adequacy. The entire description is based on the false premise that LSEs are insufficiently hedged based upon 1) a decrease in the amount of tolling agreements; and 2) a report that the Energy Division staff provided indicated the CCAs and Electric Service Providers (ESPs) were less forward contracted than IOUs. While noting that "the data are not informed by any non-commodity hedge information", CalAdvocates concludes that CCAs and ESPs are "particularly exposed to price spikes on the CAISO energy market."[14]

The RA program is and should be about providing a reliable set of resources to meet grid reliability needs. When the Commission identified an issue with imports that would allow capacity to likely not be struck due to bidding at the cap, the Commission put in place new rules to address it.[15] This proceeding has not identified a similar situation from resources interconnected to the CAISO grid. This is because such resources are not able to sell the energy coming from their capacity off grid without offering it into the CAISO market at a price that it will clear. The exact opposite was true for RA imports. Thus, the only threat to reliability with in-state resources is for an RA resource to exercise market power through financial withholding (*i.e.*, bidding the resource excessively high to avoid market-clearing making the market clear on higher-priced resources). This fails to recognize that the CAISO does have market power mitigation in place for all local area resources and has a stakeholder process in progress to evaluate system market power mitigation. In addition, post-2000 California energy crisis, the Federal Energy Regulatory Commission (FERC) has made clear that such withholding is in

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14 *Id*. at 10.

15 D.20-06-028, *Decision Adopting Resource Adequacy Import Requirements*, R.17-09-020 (June 25, 2020).

violation of FERC regulation with significant penalties to those found to have used such schemes.

Thus, other than concerns over costs to customers, the current proceeding and CalAdvocates have not advanced the reliability argument necessary to conclude that the RA program should be amended to include a market power mitigation tool. While many parties are concerned about customer costs, those concerns extend not only to CalAdvocates and the Commission but to every LSE that serves customers in California. The responsibility for the efficacy of hedges put in place to protect customers from market price volatility is not that of the Commission for every LSE even if those LSEs do have to comply with the Commission for RA reliability.

Since the proceeding has not identified a reliability threat not already addressed by other regulations including those administered by other authorities, the implementation of a market power mitigation process in the RA construct serves to regulate the financial activities of market participants outside of the jurisdiction of this Commission and should therefore be rejected.

VIII. THE COMMISSION SHOULD COORDINATE WITH THE CAISO TO ADOPT A UCAP FRAMEWORK, AS PARTIES' CONCERNS THAT UCAP WILL NOT ACHIEVE THE DESIRED MAINTENANCE INCENTIVES ARE MISGUIDED

Several parties express support for the adoption of a "UCAP-light" for thermal resource counting, meaning a thermal resource's qualifying capacity (QC) would be derated to account for thermal derates only, and not other types of forced outage.[16] CLECA expresses concern that because forced outage rates are reliant on historical performance, expanding UCAP beyond ambient derates to include other types of forced outages may discourage investments that would improve resource performance given that improved performance would take years to be reflected

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[16] CLECA, the Independent Energy Producers Association, and Shell Energy North America (US), L.P. d/b/a Shell Energy Solutions.

in the QC.[17] However, UCAP should incentivize resource maintenance better than the structure currently in place that relies on the Resource Adequacy Availability Incentive Mechanism (RAAIM) and substitution requirements. The CAISO has presented data in its RA Enhancements initiative that suggests the current structure does not result in substitutions to cover forced outages, indicating incentives to perform maintenance do not currently exist.[18]

UCAP, on the other hand, would directly utilize unit-specific past performance, the best predictor of future performance, to inform the reliability contribution of the unit for the purposes of resources adequacy. This should incentivize resources to perform maintenance and improve their reliability in the first instance to avoid forced outages and maintain a high UCAP value. Most other resources on the system are valued based on historical performance in some manner (*e.g.*, exceedance for hydro, ELCC for wind and solar) so it is unclear why parties suggest using historical information for thermal resources is inappropriate. Resources with demonstrated reliability improvements would see such results reflected in their capacity value fully within three years. To ensure maintenance that improves the reliability of a resource is more quickly reflected the net qualifying capacity, the Commission could adopt a weighting mechanism as proposed by the CAISO to weight more recent outages more heavily.[19] This would strengthen the incentives to perform planned maintenance that are already inherent within a UCAP methodology because maintenance that results in improved reliability of the plant would be reflected in the plant's RA value sooner.

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[17] *California Large Energy Consumers Association Comments on Administrative Law Judge's Ruling Seeking Comments on the Future of Resource Adequacy Working Group Report and the Local Capacity Requirement Working Group Report*, R.21-10-002 (Mar. 24, 2022), at 6-7.

[18] *Resource Adequacy Enhancements Fifth Revised Straw Proposal,* July 7, 2020, at 98-100: http://www.caiso.com/InitiativeDocuments/FifthRevisedStrawProposal-ResourceAdequacyEnhancements.pdf

[19] Final Report at 56.

For these reasons, the Commission and the CAISO should work together to adopt a UCAP framework in a coordinated manner that would improve the incentives for resources to be available and perform planned maintenance.

IX. MULTI-YEAR SYSTEM AND FLEXIBLE RA REQUIREMENTS SHOULD BE CONSIDERED IN A SUBSEQUENT PROCEEDING WHEN THE FULL IMPACTS OF SUCH CHANGE CAN BE EXAMINED

Few parties support moving to a multi-year forward system and/or flexible RA requirement at this time. CalCCA sees two important reasons not to pursue such a mechanism at this time. First, the interaction of the Central Procurement Entity (CPE) and its impact on LSE procurement would need to be evaluated. This is particularly problematic since in 2021 procurement for 2023 delivery, PG&E as the CPE had a significant short-fall in meeting the local area needs and SCE also experienced a more minor short-fall. Since all non-self-shown resources are paid by the CPE, the costs and benefits are allocated via cost allocation mechanism to all LSEs in the CPE Transmission Access Charge (TAC) Area. The current insufficient procurement by the CPEs has caused difficulty for all LSEs in completing their own system and flexible procurement for 2023. This difficulty is only somewhat mitigated by the fact that there are still seven months total before the year-ahead showing for 2023. Even with this amount of time, the LSEs are left with little time to know of their allocation and perform final procurement. If the system and flexible RA requirements are moved to a multi-year forward process the time between CPE procurement and potential CPE deficiency, prior to LSE procurement will make such a process very uncertain and potentially expensive for customers. In order to address this, the Commission needs to evaluate the efficacy of the CPE process and in doing so, would need to evaluate the necessary timing to make a CPE and LSE procurement for multiple years forward work seamlessly and effectively for the CPEs and LSEs alike.

In addition, the proceeding has yet to evaluate the interaction of load migration and the minimum requirements for a multi-year forward requirement. Given that this could be particularly difficult with no clear guidance on which structural RA reform model the Commission will choose and how transactability will be resolved, moving to a multi-year forward requirement with load uncertainty, resource counting uncertainty, and basic RA structure uncertainty seems to be an ill-advised action.

For these reasons, the Commission should not adopt a multi-year forward system and/or flexible RA requirement at this time.

X. THE COMMISSION SHOULD NOT ADOPT CALADVOCATES PROPOSED CHANGE TO THE PRM

CalAdvocates recommends the CEC develop an hourly 1-in-5 weather year forecast as part of its efforts to support the Slice-of-Day framework.[20] This recommendation builds on CalAdvocates' comments to the Energy Division's Loss of Load Expectation Study (Study) in which CalAdvocates recommend a 13 percent PRM be applied to a 1-in-5 forecast to set RA requirements. CalCCA reiterates its position in reply comments to the Study that the Commission should not adopt a new level of forecast and resulting PRM in favor of a PRM based on robust LOLE analysis.[21] 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 under any SOD framework adopted. The Commission should therefore perform a robust stakeholder process to ensure the assumptions of the LOLE study are reasonable and reflect the counting methodologies ultimately adopted under the new framework.

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[20] CalAdvocates Comments at 18.

[21] *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*, R.21-10-002 (Mar. 22, 2022), at 4.

XI. 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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April 1, 2022

California Community Choice Association

SUBMITTED 04/04/2022, 02:01 PM

Contact

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1. Please provide a summary of your organization's general comments on the revised straw proposal presentation for this initiative:

The California Community Choice Association (CalCCA) appreciates the opportunity to comment on the Energy Storage Enhancements Revised Straw Proposal (Revised Straw Proposal). In these comments, CalCCA recommends:

- Adopting the California Independent System Operator (CAISO) proposed model that allows storage operators manage state-of-charge (SOC) and reflect other operating characteristics; CalCCA requests clarification on how bids would be submitted in the day-ahead market considering the initial SOC is unknown;
- Adopting a robust market power mitigation mechanism for storage resources operating under the energy storage resource (ESR) model;
- The CAISO clarify its ancillary service proposal would only apply to resources using the non-generator resource (NGR) model, not the ESR model, to the extent necessary to satisfy their award;
- The CAISO further explain the rationale behind the time horizon proposed to calculate the counterfactuals used to establish the opportunity costs associated with exceptional dispatches (EDs) to hold SOC; a different lookout period, such as 24 hours or all hours of the day following the ED, may be more appropriate given every increment of state of charge is dependent on the previous state of charge;
- The CAISO consider the use of the proposed tools for local areas and their impact on market prices in the Transmission Planning Process (TPP) when evaluating whether or not to approve transmission upgrades that would alleviate local area constraints and reduce reliance on the use of this tool; and
- The CAISO expand its co-located enhancements proposal to allow the functionality to apply to all co-located resources, legacy or new resources, that are eligible for the Investment Tax Credit (ITC) and property tax benefits regardless of when the contract was executed relative to CAISO's proposal.

2. Provide your organization's comments on the proposed energy storage resource model, as described in the revised straw proposal:

CalCCA generally supports a model that would allow storage resource operators to manage SOC and reflect other operating characteristics but is concerned the ESR model would make it difficult to construct bids into the day-ahead market given the initial SOC going into the day would not be known when bids are submitted. CalCCA requests clarification or an example on how bids would be constructed for day-ahead, given the

SOC going into the first hour of the day will not be known when bids are submitted at 10 a.m. the day prior. This is especially important; how the resources bid will likely depend on the SOC of the resources at a defined starting point, which could vary significantly from the time bids are submitted for day-ahead to the beginning of the day.

CalCCA supports requests by stakeholders on the call for the CAISO to provide more examples that explain how the CAISO will model variable ramp rates.

With respect to the CAISO's proposal on market power mitigation, CalCCA supports a robust market power mitigation mechanism for storage resources operating under the ESR model. The CAISO's proposed methodology generally includes the correct set of costs for storage to buy energy, cycling costs, and real-time opportunity costs. In the next iteration of the proposal, the CAISO should consider what happens if the mitigated bids to discharge are below the bids to charge, given the ESR model will have separate bids to charge and discharge.

3. Provide your organization's comments on the proposed reliability enhancements for storage resources, as described in the revised straw proposal:

Ancillary Services

CalCCA understands why this proposal would be useful to CAISO operators when operating storage resources using the NGR model. However, this is likely not applicable to resources using the ESR model because the resources can bid SOC to ensure they can meet their AS awards. The CAISO should clarify this proposal would only apply to resources using the NGR model. The CAISO should also clarify in its proposal that *to the extent necessary to satisfy their award*, the storage must provide an energy bid with its ancillary service award. Storage resources may be situated in real-time in such a way that they can meet their AS award without requiring energy bids. For example, if a storage resource with a maximum capacity (Pmax) of 100 megawatts (MW) receives a 5 MW regulation up-award and the resource is operating at 80 MW, then the energy bid to charge is not needed to ensure the resource can deliver on their ancillary service award. On the other hand, if the same resource receives a 200 MW ancillary service award, then the resource would need energy bids from -100MW to 100 MW (*i.e.*, charge and discharge bids) to deliver on its ancillary service award. In this case, the CAISO does not need to enforce this requirement.

Exceptional Dispatch

CalCCA supports the CAISO implementing new functionality to allow operators to ED storage resources to hold SOC and compensating storage exceptionally dispatched to hold SOC using an opportunity cost methodology. CalCCA requests the CAISO further explain the rationale behind the time horizon proposed to calculate the counterfactuals used to establish the opportunity costs, which is currently the length of the ED plus the duration of the battery. A different lookout period, such as 24 hours or all hours of the day following the ED, may be more appropriate given every how a resource would choose to bid each increment of SOC is dependent on the previous SOC.

Tools for Local Areas

CalCCA does not oppose the CAISO's proposal to schedule energy storage resources in day-ahead through the market when operators identify challenging constraints in local areas. The CAISO should, however, consider the use of these tools and their impact on market prices in the TPP when evaluating whether or not to approve transmission upgrades that would alleviate local area constraints and reduce reliance on the use of this tool.

4. Provide your organization's comments on the proposed co-located enhancements, as described in the revised straw proposal:

Co-Located Enhancements

CalCCA appreciates the CAISO taking steps to enhance the ability of co-located resources to utilize solely on-site renewables to charge storage to take full advantage of the ITC. CalCCA supports the proposed electable functionality to limit dispatch instructions, so they are no greater than the forecast of the co-located renewable. However, CalCCA opposes the CAISO's proposal to limit this functionality to resources that have contractual ITC implications or property tax implications in place prior to this policy being implemented. The CAISO must expand its proposal to allow the functionality to apply to all co-located resources, legacy or new resources, that are eligible for the ITC and property tax benefits regardless of when the contract was executed relative to CAISO's proposal. This functionality should extend for the length of the ITC or property tax benefit eligibility, rather than being limited to five years. Resources unavailable due to grid charging restrictions should be required to submit outage cards but the outage should be exempt from RAAIM if the outage is due to charging restrictions and the inability to charge from onsite renewable.

The CAISO should not develop a policy that would require asking one federal agency (Federal Energy Regulatory Commission) to approve a policy that would directly contradict that of another. The ITC is a federal benefit offered by the Internal Revenue Service to incentivize pairing storage with renewable resources. The CAISO must not implement policies that contradict federal programs or diminish market participants' ability to take full advantage of them. The ITC is a federal benefit that could potentially extend beyond its current five-year timeframe in the future. The CAISO's proposal would create an unnecessary roadblock to market participants looking to participate under the co-located configuration, which by design is meant to allow for a more flexible utilization of the battery. Therefore, the CAISO must extend this electable functionality to all resources eligible for the ITC.

A significant reason so many storage resources are being developed is that they can be financed using ITC and receive property tax benefits. The CAISO should avoid policies that would stand in the way of developing these resources, especially during a time when the state needs to procure significant amounts of new capacity to meet procurement orders and support grid reliability. CalCCA understands the CAISO intends to be able to fully utilize the battery component of co-located resources, above their renewable output, through grid charging. This must only occur after the phaseout of ITC and property tax benefits. Only applying this functionality to existing resources with contracts signed before Energy Storage Enhancements implementation (*i.e.*, 2023) creates both uncertainty and new challenges for co-located resources coming to market, since new resources will have uncertainty around the ITC it can expect to receive.

Further, while the CAISO states its proposal, “should incentivize owners to bid more charging capability into the market, as charging would always be compensated, including incidental costs from grid charging,”[1] compensation through the CAISO market cannot offset foregone ITC payments. While it may be possible to reflect some of these costs through bids prior to reaching the 25 percent threshold, as the CAISO outlines in its proposal, storage is not eligible for ITC at all if the percentage of charging that occurs via the grid rather than the onsite renewable exceeds 25 percent. These costs significantly exceed those that can be reflected through bids. This is exacerbated by the foregone property tax benefits that are lost by any amount of grid charging.

Finally, CalCCA requests clarification on the process by which market participants would have the ability to request the functionality be added or removed. CalCCA understands that the New Resource Implementation (NRI) process can take a considerable amount of time, and if the process for adding or removing this functionality is similar to the NRI process, it may impact decisions around which model (hybrid or co-located) to use.

Optimized Curtailment of Co-Located Resources

CalCCA supports the comments from Clean Power Alliance (CPA) submitted to the Revised Straw Proposal regarding the curtailment of co-located resources. CPA’s proposal would adjust curtailment orders on co-located resources so that renewables can continue to charge on-site batteries as scheduled, rather than having the renewable resource curtailed such that the storage cannot fully charge. Given co-located resources are prevented from charging from the grid, when the CAISO issues a curtailment instruction, the resource can curtail such that it provides 0 MW of export onto the grid but should be able to produce energy such that it can continue to charge the storage component. Curtailing the renewable resource further such that it provides no energy to the grid and also cannot fully charge the battery would only result in the CAISO having less energy available from the storage component to dispatch at a later time.

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[1] Revised Straw Proposal at 23.

5. Provide your organization’s comments on the proposed WEIM classification for this initiative, as described in the revised straw proposal:

CalCCA has no comments at this time.

6. Attachments

CalCCA has no comments at this time.

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Compliance Review of Utility-Owned Generation Operations, Portfolio Allocation Balancing Account Entries, Energy Resource Recovery Account Entries, Contract Administration, Economic Dispatch of Electric Resources, Utility-Owned Generation Fuel Procurement, and other Activities for the Record Period January 1 Through December 31, 2021. (U 39 E)	Application No. 22-02-015

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S PROTEST TO THE APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY

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April 6, 2022

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Compliance Review of Utility-Owned Generation Operations, Portfolio Allocation Balancing Account Entries, Energy Resource Recovery Account Entries, Contract Administration, Economic Dispatch of Electric Resources, Utility-Owned Generation Fuel Procurement, and other Activities for the Record Period January 1 Through December 31, 2021. (U 39 E)	Application No. 22-02-015

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
PROTEST TO THE APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY

Pursuant to Rule 2.6 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission" or "CPUC"), the California Community Choice Association[1] ("CalCCA") hereby protests the relief sought in the above-captioned *Application of Pacific Gas and Electric Company (PG&E) for Compliance Review of Utility-Owned Generation Operations, Portfolio Allocation Balancing Account Entries, Energy Resource Recovery Account Entries, Contract Administration, Economic Dispatch of Electric Resources, Utility-Owned Generation Fuel Procurement, and other Activities for the Record Period January 1 Through December 31, 2021. (U 39 E)* ("Application").

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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 (EBCE), Lancaster Choice Energy, Marin Clean Energy (MCE), Orange County Power Authority, Peninsula Clean Energy (PCE), 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 (SJCE), Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

In its Application, PG&E requests that the Commission find:

1. that it prudently administered and managed its utility-owned generation ("UOG") facilities and Qualifying Facility ("QF") and non-QF contracts in compliance with all applicable rules, regulations and Commission decisions;
2. that it achieved least-cost dispatch of its energy resources and economically-triggered demand response programs pursuant to SOC 4;
3. that the entries recorded in the Energy Resource Recovery Account ("ERRA") and the Portfolio Allocation Balancing Account ("PABA") are reasonable, appropriate, accurate and in compliance with Commission decisions;
4. that its fuel procurement and hedging activities complied with its Commission-approved Bundled Procurement Plan ("BPP");
5. that its resource adequacy sales complied with the BPP;
6. that the costs incurred and recorded in the Green Tariff Shared Renewables Memorandum Account ("GTSRMA"), Green Tariff Shared Renewables Balancing Account ("GTSRBA"), DAC-SASH balancing account ("DACSASHBA"), Disadvantaged Communities Green Tariff Balancing Account ("DACGTBA"), the Community Solar Green Tariff Balancing Account ("CSGTBA"), and the Centralized Local Procurement Sub-Account ("CLPSA") in the New System Generation Balancing Account ("NSGBA") are reasonable and in compliance with applicable tariffs and Commission directives.[2]

The impact of PG&E's Application on both departed and bundled customers requires cautious and careful consideration under the applicable standards of review. PG&E, as the

[2] Application at 20.

applicant, has the burden of proof[3] and must satisfy that burden based on a preponderance of the evidence.[4]

CalCCA protests the Application on the grounds that the utility has fallen short of demonstrating that the entirety of the relief it seeks meets the utility's burden. CalCCA has identified several issues below that should prevent immediate adoption of the relief requested in the Application without further examination before the Commission. CalCCA respectfully requests that the Commission set this matter for hearing to fully examine those issues together with any other issues that may arise during the course of this proceeding.

I. CALCCA'S INTEREST

As noted above, CalCCA represents the interests of 23 community choice aggregators ("CCAs") in California, including 11 CCAs that serve PG&E's delivery service customers. Except for SJCE and CleanPowerSF, each of those CCAs is governed by a Board of Directors comprised of elected officials who represent the individual cities and counties the CCA serves, or an elected City Council. CleanPowerSF is the CCA for the City and County of San Francisco, which the San Francisco Public Utilities Commission operates. SJCE is the City of San Jose's CCA program, which the San Jose Community Energy Department administers. While CalCCA's advocacy frequently benefits both bundled and unbundled customers, the CCAs are the sole advocates for their customers and their local energy programs before this Commission.

CCA customers receive generation services from their local CCA and receive transmission, distribution, billing, and other services from PG&E. As such, CCA customers in

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[3] D.12-12-030 at 42; Application at 4.

[4] *See, e.g.* D.18-01-009 at 9-10; D.15-07-044 at 29 (observing that the Commission has discretion to apply either the preponderance of evidence or clear and convincing standard in a ratesetting proceeding but noting that the preponderance of evidence standard is the "default standard to be used unless a more stringent burden is specified by the statute or the Courts."); Application at 4.

PG&E's service territory must pay the same electric distribution, transmission and non-bypassable rates as PG&E's bundled customers. However, CCA customers pay CCA-specific generation rates, which vary and are partially influenced by local mandates to increase electric vehicle use, procure and maintain clean electricity portfolios that in many cases exceed state requirements for renewable generation, and achieve other local goals. For example, last year, PCE became the first load-serving entity in California to provide 100% greenhouse-gas free energy to each of its customers, well in advance of the State's 2045 goal.

CCA and other unbundled customers are also subject to several non-bypassable charges, including the Power Charge Indifference Adjustment ("PCIA"). The Commission adopted the PCIA to ensure that when investor-owned utility ("IOU") customers depart from bundled service and receive their electricity from a non-IOU provider, such as a CCA, "those customers remain responsible for costs previously incurred on their behalf by the IOUs—but only those costs."[5] The level of the PCIA during the 2021 record period was determined, initially, in Decision (D.) 20-12-038 as a forecast of the above-market costs stemming from PG&E's generation portfolio over the course of that year. Prior to D.18-10-019, the PCIA rate was set only on this forecast basis and not trued-up for unbundled customers - only bundled customers' rates were subject to a true-up.

D.18-10-019 requires that PG&E true up the forecasted costs (net of forecasted market revenues or imputed revenues) approved in D.20-12-038 with the actual recorded costs (net of actual market revenues or imputed revenues) for PCIA-eligible resources.[6] It also requires PG&E to true up the revenues it forecasted it would receive from both bundled and departing load

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5 D.18-10-019 at 3 (October 11, 2018); *see also* R.17-06-026, *Scoping Memo and Ruling of Assigned Commissioner* at 2 (September 25, 2017).

6 *Id.*, at Ordering Paragraphs ("OPs") 7 and 8.

customers over the course of 2021 with the actual revenues it received.[7] This true-up occurs by comparing the forecasted costs and revenues to the recorded costs and revenues within the PABA.[8]

As noted in more detail below, issues relating to whether the entries that PG&E recorded in the PABA (and the ERRA) are reasonable, appropriate, accurate, correctly stated, and in compliance with Commission decisions are within scope in this docket.[9] Moreover, PG&E's management of its generation portfolio and its third-party contracts, as well as its compliance with Commission-approved procurement and resource sales frameworks, directly impact the costs and revenues recorded to the PABA. Since the PABA impacts the PCIA rates that CCAs' customers pay, CalCCA has a direct, clear, real, present, tangible, and pecuniary interest in the outcome of this proceeding.

Finally, it is important to note that the true-up of the PCIA via the PABA reflects the full amount of above-market costs recovered from *both* bundled service and departing load customers. All above-market costs for PG&E's PCIA-eligible generation portfolio are now paid by both bundled and unbundled customers, which share a portion of the PCIA revenue requirement obligations. The ERRA revenue requirement includes the remaining, at-market portion of the forecasted procurement costs for PG&E's bundled customers. Therefore, as will become evident over the course of this proceeding, many of CalCCA's interests in this case are closely aligned with those of PG&E's remaining bundled customers.

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7 D.18-10-019 at Ordering Paragraphs ("OPs") 7 and 8.

8 A.21-03-008, Prepared Testimony (March 1, 2021) ("PG&E Prepared Testimony").

9 *See* A.20-02-009, Scoping Ruling at 3 (setting the standard of review) (June 19, 2020).

II. GROUNDS FOR PROTEST

CalCCA has identified several issues that impact the interests described above. The specific issues enumerated below should be considered preliminary matters that CalCCA has identified. CalCCA is still examining the Application, conducting discovery, and communicating with PG&E to better understand and analyze the utility's recorded entries for 2021. CalCCA reserves the right to address and protest additional issues within the scope of this proceeding as they arise through continued review, analysis, discovery and investigation of all aspects of the Application and supporting testimony.

A. Vintaging of Utility-Owned Generation

In its testimony, PG&E explains that following Commission Decisions 18-10-019 and 19-10-001, which significantly modified the accounting for the PCIA, management requested that PG&E Internal Audit ("IA") perform an audit of the processes and controls employed to record certain generation and procurement related costs and revenues to the PABA after the first record period was complete. IA finalized its audit in July 2020. Among other findings, IA found that it "could not determine the validity of the vintage classification for several UOG resources due to a lack of a formal definition of the UOG construction start date."[10] IA recommended that management establish "a formal definition of the construction start date that can be consistently applied."[11]

In response, PG&E's Power Generation, Accounting, and Rates teams developed the following formal definition of "UOG construction start date":

> For the purpose of determining the "Construction Start Date" for PCIA-eligible utility owned (UO) generation resources and storage resources, PG&E shall use the later of: (1) the first date that expenditures are recorded to SAP Project Order(s) established for

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10 PG&E Testimony at 12-4:8-10.

11 *Id.* at 12-4:11-13.

> the resource that are associated with site-specific construction work and that will be capitalized once the project reaches commercial operation, or (2) the date the Commission approves the new generation resource for cost recovery. Alternatively, if the Commission decision directing procurement assigns a resource vintage prior to selection of the resource, the Commission-assigned vintage will supersede vintaging the resource based on a construction start date.[12]

PG&E analyzed whether any resources were assigned to the incorrect vintage under this definition of "Construction Start Date" and evaluated whether or not to reassign such resources or make accounting adjustments. PG&E explains that "[o]nly three resources would have been assigned a different vintage under the new formal definition of "Construction Start Date"" and recommends "grandfathering" those resources into their existing vintages.[13]

CalCCA notes that PG&E's proposed definition of "Construction Start Date" may be reasonable and may provide necessary clarity to establish UOG vintage for cost recovery purposes. However, CalCCA has concerns regarding PG&E's proposed definition which may require discovery to resolve. Specifically, PG&E's proposed definition of "Construction Start Date" is based in part on "the first date that expenditures are recorded to SAP Project Order(s) established for the resource." PG&E has not explained whether that date would be reasonably ascertainable by any entity except PG&E and therefore CalCCA has concerns regarding the transparency (or lack thereof) of construction start dates (and resulting UOG vintages) under PG&E's proposed definition. To the extent that PG&E's proposed definition of "Construction Start Date" is reasonable, CalCCA will also investigate whether it is reasonable—as PG&E proposes—to "grandfather" the three resources that should be assigned a different vintage under that definition into their existing vintages.

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[12] PG&E Testimony at 12-4:20-30.
[13] *Id.* at 12-4:34-37.

B. Prior Period Entries

In its testimony, PG&E describes certain matters in which PG&E and a counterparty engaged in a dispute resolution process.[14] Depending on the time period that each of those disputes related to, the disputes (and their respective resolutions) may require prior period adjustments. CalCCA will investigate these disputes through discovery and will present testimony and legal briefing as necessary to address any prior period adjustments required as a result of these disputes.

PG&E also explains that on December 20, 2013, the California Independent System Operator ("CAISO") issued a market notice announcing settlement adjustments affecting trade days July 16, 2004 to March 31, 2009.[15] On June 26, 2014, PG&E received a $35,464,297 payment from CAISO for these historical settlement adjustments.[16] And in May 2021 and September 2021, PG&E received a total of $22,079,810 in credits for interest payments on the $35,464,297 for the period June 19, 2014 through September 17, 2021.[17] PG&E states that the $22,079,810 in interest payment credits were booked into ERRA.[18] PG&E's accounting for the interest payment credits received in 2021 (but pertaining to the period June 19, 2014 through September 17, 2021) requires further scrutiny. To the extent that credits relate to overpayments made not only by bundled customers but also by unbundled customers (prior to departing PG&E bundled service), those customers should also receive the benefit of the interest payment credits that PG&E received during the record period. CalCCA will investigate this issue through

14 PG&E Testimony at 9-15 – 9-17.
15 *Id.* at 10-5:31-33.
16 *Id.* at 10-6:8-9.
17 *Id.* at 10-6:10-13.
18 *Id.* at 10-6:13-14.

discovery and may submit testimony and legal briefing to address the appropriate accounting for the $22,079,810 in interest payment credits that PG&E received from CAISO in 2021.

C. Contract Amendments

Chapter 9 of PG&E's testimony in this proceeding concerns PG&E's contract administration practice, changes that occurred to the contracts administered, and the results achieved regarding contract administration during the record period.[19] PG&E must show that the entries recorded in the ERRA and the PABA are reasonable, appropriate, accurate, and in compliance with Commission decisions, that it adhered to Standard of Conduct 4, and that it prudently administered its contracts.[20] In Table 9-9, PG&E describes certain contract amendments and consent to assignment during the record period.[21]

CalCCA has identified certain contracts that may reflect material modifications from the original terms and, therefore, require further investigation to determine whether those contracts must be re-vintaged. In particular, several contract amendments addressed emergency procurement requirements for summer 2021. CalCCA will review those amendments to determine whether PG&E has recorded the incremental costs of such procurement to the appropriate cost recovery vehicle. To the extent that PG&E renegotiated material terms of its contracts in 2021, CalCCA contends that the contracts should be re-vintaged accordingly and will present testimony and legal briefing on this matter over the course of this proceeding.[22]

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[19] PG&E Testimony at 9-1:11-14.

[20] *See* Application at 17-18.

[21] PG&E Testimony at 9-30.

[22] The core principle of vintaging is to identify when a contract commitment is made or renegotiated for a resource so that customers may be assigned responsibility for that resource. *See* D.04-12-048 at 55; D.08-09-012 at 59. If a resource commitment is made after CCA load has departed, then customers of that CCA should not be fiscally responsible for that power resource because the resource was not procured on their behalf. *See* A.20-02-009, Joint CCA Opening Brief at 17-20.

D. Supplemental Testimony on Internal Audit

PG&E's testimony references PG&E's Internal Audit department's audit of processes and controls used to record certain entries to PABA.[23] That audit, performed on the PABA during the 2020 record period, concluded that PG&E's processes and controls were "Not Adequate" and described a series of recording errors in the PABA. In PG&E's 2020 ERRA Compliance proceeding, A.21-03-008, the Joint CCAs requested that the Commission require PG&E to demonstrate that all identified systemic process and control issues have been corrected, report whether it has taken all the steps necessary to remedy each of the audit report findings, and ensure it has adequate processes and controls in place to reduce the risk of accounting errors in the PABA.[24]

Accordingly, Ordering Paragraph 3 in the Proposed Decision on PG&E's 2020 ERRA Compliance application requires that PG&E provide, in its 2021 ERRA Compliance filing, the following:

- Testimony describing the actions PG&E has taken or will take to address the deficiencies reported in its 2020 Internal Audit Report on the PABA;
- An internal audit closure document with details of PG&E's implementation of any action plans to address the deficiencies reported in PG&E's 2020 Internal Audit Report; and
- Testimony from PG&E's Chief Regulatory Officer on the actions PG&E has taken or will take to ensure that there is proper accounting and recording of entries in the various balancing and memorandum account reviewed.[25]

Should the Commission adopt the PD including the above Ordering Paragraph, PG&E will be required to submit supplemental testimony in this proceeding. CalCCA will review that testimony and evaluate whether that testimony raises any additional concerns regarding whether

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23 PG&E Testimony at 12-1:9-11.
24 A.21-03-008, Proposed Decision at 16 (Mar. 16, 2022).
25 *Id.*, OP 3.

PG&E's entries to the PABA are reasonable, appropriate, accurate, and in compliance with Commission decisions.

E. Other Issues that Require Further Investigation and Analysis

CalCCA hopes to work with PG&E over the course of this proceeding to review PG&E's workpapers and better understand, investigate and potentially submit testimony regarding various components of the Application, including but not limited to:

- Whether PG&E's accounting of costs associated with various procurement are correctly, appropriately and accurately recorded to ERRA and PABA in compliance with Commission decisions;
- Whether PG&E's accounting of CAISO settlement charges and revenues are correctly, appropriately and accurately recorded to ERRA, PABA and other balancing accounts in compliance with Commission decisions;
- Whether PG&E's administrative costs associated with the implementation and operation of the Central Procurement Entity are correctly, and accurately recorded to the appropriate balancing accounts in compliance with Commission decisions, and;
- Green Tariff Shared Renewable ("GTSR")-related issues such as whether revenue from GTSR customers was booked to the correct balancing accounts.

III. ISSUES, CATEGORIZATION OF PROCEEDING, NEED FOR HEARINGS AND PROPOSED PROCEDURAL SCHEDULE

A. Scope of Issues to be Considered

PG&E's Application proposes the following issues for consideration in this proceeding:

1. Whether PG&E, during the record period, prudently administered and managed the following, in compliance with all applicable rules, regulations, and Commission decisions, including but not limited to Standard of Conduct No. 4 (SOC 4):

   a. Utility-Owned Generation Facilities;

   b. Qualifying Facilities (QF) Contracts and Non-QF Contracts;

   If not, what adjustments, if any, should be made to account for imprudently managed or administered resources?

2. Whether PG&E achieved least-cost dispatch of its energy resources and economically-triggered demand response programs pursuant to SOC 4;

3. Whether the entries recorded in the Energy Resource Recovery Account and the Portfolio Allocation Balancing Account are reasonable, appropriate, accurate, and in compliance with Commission decisions;

4. Whether PG&E's greenhouse gas instrument procurement complied with its Bundled Procurement Plan;

5. Whether PG&E administered resource adequacy procurement and sales consistent with its Bundled Procurement Plan;

6. Whether the costs incurred and recorded in the following accounts are reasonable and in compliance with the applicable tariffs and Commission directives:

   a. Green Tariff Shared Renewables Memorandum Account;

   b. Green Tariff Shared Renewables Balancing Account;

   c. Disadvantaged Community – Single Family Solar Affordable Homes Balancing Account;

   d. Disadvantaged Community – Green Tariff Balancing Account;

   e. Community Solar Green Tariff Balancing Account;

   f. Centralized Local Procurement Sub-Account;

7. Whether there are any safety considerations raised by this Application.

This statement of issues encompasses the issues CalCCA has raised in this Protest. CalCCA does not recommend any specific modification to PG&E's list to include those issues.

B. Categorization

CalCCA agrees with the categorization of this proceeding as ratesetting.[26]

[26] *See* Application at 17.

C. Need for Hearings

While CalCCA shares PG&E's hope to resolve the issues raised by this Application without hearings[27], CalCCA agrees that evidentiary hearings may be necessary to present facts related to those issues.

D. Schedule

CalCCA has conferred with PG&E, the Public Advocates Office, and other groups anticipated to participate in this proceeding as parties, and can represent that those groups have agreed on the following mutually acceptable alternative to the procedural schedule proposed in PG&E's application:

Application Filed	February 28, 2022
Protests and Responses Filed and Served	30 days after Daily Calendar Notice
Reply filed	10 days after Protests and Responses
Prehearing Conference	June 8, 2022
Cal Advocates and Intervenor Testimony	August 24, 2022
Rebuttal testimony served	October 3, 2022
Settlement Discussions	October-November 2022
Evidentiary Hearings	November 14-16, 2022
Concurrent Opening Briefs	December 2, 2022
Concurrent Reply Briefs	December 19, 2022
Proposed Decision	TBD
Final Decision	TBD

CalCCA submits that this proposed alternative is more reasonable than the original schedule that PG&E proposed because it will minimize overlap and conflicts with major anticipated procedural deadlines for the IOUs' ERRA Forecast cases. Moreover, to the extent that the Commission adopts the Proposed Decision ("PD") in PG&E's 2020 ERRA Compliance case (as mentioned above), the alternative procedural schedule described above will give PG&E

27 *See* Application at 17.

additional time to develop the supplemental testimony required by that PD and give the parties additional time to review that testimony, before the prehearing conference. CalCCA therefore requests that the Commission approve this agreed-upon proposed alternative procedural schedule for this proceeding.

IV. COMMUNICATIONS

CalCCA consents to "email only" service and requests that the following individuals be added to the service list for A.22-02-015 on behalf of CalCCA:

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V. CONCLUSION

For all the foregoing reasons, CalCCA respectfully requests the Commission set this matter for hearing to fully examine the issues discussed above.

Respectfully submitted,

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Dated: April 6, 2022

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S INFORMAL COMMENTS ON THE RELIABILITY & OTHER FILING REQUIREMENTS FOR LOAD SERVING ENTITIES' 2022 INTEGRATED RESOURCE PLANS – APPROACH

MODELING ADVISORY GROUP (MAG) WEBINAR, ENERGY DIVISION
April 7, 2022

The California Community Choice Association[1] (CalCCA) submits the following informal comments on the "*Reliability & Other Filing Requirements for Load Serving Entities' 2022 Integrated Resource Plans – Approach" Modeling Advisory Group Webinar* (MAG Webinar),[2] held on April 7, 2022, and offers the following suggestions to the California Public Utilities Commission (Commission) to improve the efficacy of the Integrated Resource Plan (IRP) process.

I. THE COMMISSION SHOULD MAKE CRUCIAL MODELING DATA AVAILABLE IN JUNE TO GIVE LOAD SERVING ENTITIES (LSES) TIME TO PLAN THEIR PORTFOLIOS

During the MAG Webinar, the Commission stated that "the filing requirement assumptions that LSEs need for developing their 2022 IRP plans will be finalized by June 15, 2022."[3] The Commission further stated that "CPUC staff expects to finalize the 2022 Inputs and

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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 MAG Webinar located at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2022-irp-cycle-events-and-materials/20220407-fr-and-reliability-mag-slides.pdf

3 MAG Webinar at 9.

Assumptions (I&A) document, including the stakeholder process, by early/mid Q4 2022",[4] and that the LSE filings would be due November 1, 2022.[5]

While CalCCA acknowledges the IRP is a planning document subject to changing inputs and assumptions over time, it is important to recognize that any significant changes to planning assumptions between the release of the filing requirements in June and the release of the final I&A document in Q4 may materially impact the validity of LSE plans.[6] To ensure the plans filed in November are the best possible approximation of requirements to meet the final PSP, CalCCA urges staff to finalize as many of the PSP I&A assumptions as possible prior to June 15th and align them with the provided filing requirements.

CalCCA therefore requests that the Commission provide a complete list of assumptions that will be finalized by June 2022. At a minimum, this list should include the following in order to help LSEs create their plans.

- Guidance on the simultaneous import limit that LSEs should assume at times of high system stress. As CalCCA has previously flagged in comments, the Commission uses 4 gigawatts (GW) in its modeling, whereas the California Independent System Operator Corporation (CAISO) uses 5.5 GW.[7] The Commission should work with the CAISO to resolve the discrepancy and clarify the simultaneous import limit that stakeholders should use in their modeling.

- Clarity on the level of annual Planning Reserve Margin (PRM) that will be the basis of the reliability check for the plans.

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4 MAG Webinar at 10.

5 *Id.* at 12.

6 CalCCA has previously flagged this timeline issue in comments. *See California Community Choice Association's Comments on the Proposed Decision Adopting 2021 Preferred System Plan*, R.20-05-003 (Jan. 14, 2022), at 10-11. "The PD Should Be Modified to Require Planning Standards to be Provided Earlier, and Allow LSEs at Least 180 Days After Receiving Final Planning Standards to Submit IRP Plans."

7 *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*, R.21-10-002 (Mar. 14, 2022), at 5-8.

- Transmission cost and availability, per Tables 37 (Transmission Availability and Cost in CAISO) and 39 (Transmission Costs for Out-of-State resources) in the last IRP cycle's release of the I&A document.[8]

- Information that will allow LSEs to model Northern Nevada Geothermal as a candidate resource in their portfolios. This includes Effective Load Carrying Capacity (ELCC), resource availability, transmission constraints, transmission upgrade options, fixed operations and maintenance (O&M) costs, and variable O&M costs. The Commission should also add Northern Nevada Geothermal as a discrete Renewable Energy Solutions Model (RESOLVE) resource type in IRP templates.

- ELCC factors, by year, for both the required 30 Million Metric Ton (MMT) and 25 MMT portfolios.

- Clarification that the Commission will use both the 30 MMT and 25 MMT ELCC factors to evaluate reliability of the portfolio—*i.e.*, the template will calculate the LSE's total Net Qualifying Capacity (NQC) under both a 30 MMT target and a 25 MMT target and ensure that both NQCs exceed the LSE's load plus the PRM.

- Clarification on the timeline of the reliability check described above—*i.e.*, will this extend out to 2035, or for the next few years?

- Guidance on counting the NQC contribution of resources that do not have calculated ELCCs.

- An updated list of baseline resources, or, alternatively, confirmation that the 2021 Preferred System Plan (PSP) baseline list[9] should be used.

II. THE COMMISSION SHOULD UPDATE THE IRP FILING TEMPLATES TO IMPROVE USABILITY AND REDUCE REDUNDANT REQUIREMENTS

CalCCA supports Energy Division's proposal to update the IRP filing requirements,[10] including the Resource Data Template (RDT), Narrative Template (NT), and the Clean System

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[8] *Inputs & Assumptions: 2019-2020 Integrated Resource Planning*. Located at: https://files.cpuc.ca.gov/energy/modeling/Inputs%20%20Assumptions%202019-2020%20CPUC%20IRP%202020-02-27.pdf, at 55 and 57.

[9] Located at: https://files.cpuc.ca.gov/energy/modeling/Aggregated%20LSE%20Plans%20and%20Baseline%20and%20Dev%20Resources_V5.xlsx

[10] MAG Webinar at 11-16.

Power (CSP) calculator, and offers the following specific suggestions for improvements on these materials.

First, the RDT should not require LSEs to enter data for short-term Resource Adequacy (RA) only (RA-only) or short-term Renewable Portfolio Standard (RPS) energy attribute contracts for 2022 and 2023. LSEs already submit RA contract information as part of their year-ahead filings in the RA process, which performs a reliability check by comparing an LSE's planned procurement with their contracting obligation. Similarly, LSEs already provide RPS contract information as part of the RPS proceeding. Thus, a separate RA and RPS check in IRP for those years is redundant. Additionally, a typical LSE may have thousands of rows of data representing these contracts, which include both purchases and sales. Gathering and entering data for all these short-term contracts is burdensome and creates unnecessary work filling out the template, with dubious analytical value. One community choice aggregator (CCA) shared that in their 2019 RDT, 120 of the 153 entered contracts were short-term and not indicative of long-term planning.

Second, the RDT should output a summary table of LSE new build that an LSE can quickly copy and paste into the inputs of the CSP tool. This will provide LSEs with clarity on which subset of RDT resources are appropriate to include in the CSP tool. For example, it is likely not appropriate for an LSE to include RA-only batteries in the CSP tool. This is because RA-only batteries do not necessarily charge and discharge at certain hours to perform energy arbitrage, meaning they do not have a material effect on an LSE's emissions.

Third, the Commission should request that LSEs combine both their 30 MMT and 25 MMT portfolios into a single RDT. This improves ease of use and helps with data entry and validation.

Fourth, the NT should include a section allowing LSEs to describe their building electrification and Electric Vehicle (EV) charging infrastructure investments above and beyond what is included in Integrated Energy Policy Report (IEPR). Currently these items are not fully captured in the statewide IEPR Forecast, which uses a simple load-share basis to estimate electrification and EV by LSE. These building electrification and EV efforts may lead to increases in electric sector emissions but drive overall emissions down – an important consideration in evaluating the performance of LSE activities.

III. THE COMMISSION SHOULD USE A PLANNING RESERVE MARGIN IN TERMS OF GROSS PEAK, NOT NET PEAK

At the MAG Webinar, Energy Division proposed to calculate "a perfect capacity (PCAP) based total reliability need (TRN), translate into a planning reserve margin (PRM) above median gross peak."[11] CalCCA supports this "gross peak" approach. In a gross peak regime, the PRM will be based solely on operating reserves and load uncertainty, **not** the uncertainty of output from intermittent BTM resources such as load and batteries.[12] Because the gross peak PRM is agnostic to the uncertain amount of BTM solar and batteries available at peak, it would keep the PRM stable as the penetration of those resources increased over time—an outcome which is desirable for grid planners. Gross peak PRM is also fairer because it does not combine the effect of all the BTM uncertainty into a single coarse PRM number that applies to all LSEs, which effectively penalizes LSEs with lower penetrations of BTM resources. For example, an LSE with

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[11] Mag Webinar at 57.

[12] BTM resources would be counted on the supply side. This implies that the Commission should separately calculate ELCC values for BTM solar, BTM battery, in-front-of-meter (IFOM) solar, and IFOM battery. In the RDT, these resources should be assigned those ELCC values to calculate their contributions to reliability.

no BTM resources would be forced to procure more, even though they did not cause any of the higher PRM.

Improving the durability of PRM should not, however, come at the expense of a significant administrative burden. The Commission could use several existing data sources for forecasting BTM resources. LSEs are required to report forecasted BTM installs, energy, and peak demand impact in Form 3 of the IEPR—for instance, the 2021 filing required entries through 2026. The Commission could ask for this data from the California Energy Commission and use it to build an allocation of statewide BTM. Also, starting in 2021, the CAISO started requiring LSEs to report hourly aggregated excess BTM volumes.[13]

The Commission could request a summary of these values from the CAISO and use them to allocate existing BTM between LSEs. The Commission could also use data from the Self-Generation Incentive Program Energy Storage Evaluation reports to calculate BTM storage dispatch.[14]

IV. IN THE RELIABILITY CHECK, THE COMMISSION SHOULD ASSIGN THERMAL RESOURCES A UCAP VALUE

The Commission should use the unforced capacity (UCAP) methodology to calculate capacity value for thermal resources, as CalCCA has previously explained in comments.[15] UCAP uses *unit-specific* past performance to calculate each thermal resource's contribution to

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[13] These volumes are "grid exports" and less than the BTM generator output which serves on-premise load as well.

[14] For example, the 2019 Self-Generation Incentive Program Energy Storage Impact Evaluation report contains tables showing storage charge and discharge by hour. See p. 51, Figure 4-15: "Average Hourly Discharge (kWh) per capacity for nonresidential systems. Report located at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/self-generation-incentive-program/sgip-2019-energy-storage-impact-evaluation.pdf.

[15] *California Community Choice Association's Reply Comments on Administrative Law Judge's Ruling Seeking Comments on the Future of Resource Adequacy Working Group Report*, R.21-10-002 (Mar. 22, 2022) (CalCCA Reply Comments), at 11-13.

reliability, meaning it provides the most accurate possible data on a resource's likely contribution to future reliability (in contrast to calculations at the resource class level, such as PCAP.) In addition, UCAP improves on the existing incentives for generator maintenance because it rewards generators for reducing their outage rates with a higher capacity value.[16]

V. THE COMMISSION SHOULD EVALUATE IF THE PROPOSED PROCUREMENT IN THE PSP IS REALISTIC, GIVEN THE CAISO INTERCONNECTION QUEUE

The CAISO publishes the interconnection queue, which should contain all resources that are planned to come online in the next few years (including many that will not, due to contract failure, etc.). The Commission should align the cap on MW/year in the PSP with the CAISO's expectations for granting deliverability, given these current interconnection queue constraints. In other words, in the near term, the Commission should not expect LSEs to procure at a rate faster than the CAISO can grant deliverability.

IV. CONCLUSION

CalCCA appreciates the opportunity to comment on the April 7, 2022 MAG Webinar and urges the Commission to consider the recommendations herein.

Date: April 21, 2022

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16 CalCCA Reply Comments at 12.

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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 REPLY COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING DISTRIBUTING WORKSHOP AGENDA AND PROVIDING QUESTIONS FOR ADDITIONAL POST WORKSHOP COMMENTS

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April 15, 2022

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  - The Commission should not require all CCAs to obtain a credit rating;
  - The Commission must apply financial monitoring and risk management requirements comparably between CCAs and ESPs;
- The Legislature did not authorize the Commission to unilaterally terminate CCA service;
- Requiring LSEs to include contract provisions for assignment to the POLR would risk unenforceability in bankruptcy, increased customer costs, and unintended market consequences; and
- A Commission-regulated public benefit central entity is a better long-term solution for POLR service, reliability and other critical functions.

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CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY 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 Reply 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

Like most rulemakings, this proceeding requires the California Public Utilities Commission (Commission) to strike the right balance among competing interests. Senate Bill (SB) 520 articulates two objectives for Phase 1 of this proceeding: (1) ensuring California can continue to meet its greenhouse gas emissions (GHG) reduction and air quality goals,[3] and (2)

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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).

3 Cal. Pub. Util. Code § 387(h).

avoiding disruption of electric service if a load-serving entity (LSE) fails.[4] Commission staff and parties to this proceeding have raised other critical goals, including preventing cost shifts to bundled customers[5] and mitigating the effects of any customer return on new project development.[6] Addressing these concerns, however, serves little purpose if community choice aggregator (CCA) failure becomes a self-fulfilling prophecy because the adopted "insurance" against failure drives CCAs out of the market. Consequently, impacts on CCA viability and customer affordability must be an overriding concern in balancing the interests in play.

Assessing trade-offs among these interests requires the Commission to assess risk. The risk associated with any particular event – here, a return of customers – is a function of the likelihood of failure and the consequences of failure. Designing risk mitigation considering only the *consequences* of failure without considering *likelihood* will lead to unnecessarily costly solutions. For example, requiring security based on a presumption that a "black swan" or "tsunami" event will occur and that such an event will result in the return of all non- investor-owned utility (IOU) load to the Provider of Last Resort (POLR) would be excessive. While an extreme event is possible, it is significantly less likely than other causes for returns. In fact, the two customer returns raised during this proceeding -- Western Community Energy (WCE) and Baldwin Park Resident Owned Utility District (BProud) – were caused by other circumstances, and their impacts were limited. These two entities represented 2.3 percent of the peak load in the Southern California Edison Company (SCE) Transmission Access Charge (TAC) area.

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4 Cal. Pub. Util. Code § 387(j).

5 Provider of Last Resort (POLR) Workshop #2, R.21-03-011 (Mar. 7, 2022), at Slide 8.

6 *Comments of the California Energy Storage Alliance on the Administrative Law Judge's Ruling Distributing Workshop Agenda and Providing Questions for Additional Post Workshop Comments,* R.21-03-011 (Mar. 28, 2022) (CESA Comments); and *Comments of the Solar Energy Industries Association and the Large-Scale Solar Association on Questions Presented in Administrative Law Judge Ruling and March 7, 2022, Workshop*, R.21-03-011 (Mar. 28, 2022) (SEIA/LSA Comments).

Moreover, while California experienced an extreme event in 2000-2001, San Diego Gas & Electric (SDG&E) correctly observes that the conditions in California's markets that led to that event are no longer present.[7] And notably, during that event, which cost California ratepayers billions of dollars, there were no CCAs; IOU customers had to face the consequences. The extent of security required to prepare for potential customer returns must be reasonably set in the context of the relative risk.

Parties' opening comments advanced recommendations that would lead to an unbalanced solution to address the risk of customer return, and CalCCA urges the Commission to consider the following replies in developing a solution:

- The Commission should ensure the balance and accuracy in the financial security requirement (FSR) calculation rather than replace the FSR with an out-sized liquidity pool;
    - The definition of risks should include not only the consequence but also the probability of the outcome;
    - SCE and SDG&E's proposed FSR changes are imbalanced and require additional changes to improve the accuracy of the calculation;
    - The need to remove surety bonds as a security instrument has not been sufficiently demonstrated;
- Any financial monitoring must make use of existing public information and should be aimed solely at providing the Commission advance notice of likely customer returns;
    - The Commission should develop an administratively simple approach to financial monitoring as opposed to a complex approach resulting in premature action by the Commission;
    - The Commission should not require all CCAs to obtain a credit rating;
    - The Commission must apply financial monitoring and risk management requirements comparably between CCAs and Electric Service Providers (ESP);

[7] *Response of San Diego Gas & Electric Company (U 902 E) to Administrative Law Judge's Ruling,* R.21-03-011 (Mar. 28, 2022) (SDG&E Comments), at 4-5.

- The Legislature did not authorize the Commission to unilaterally terminate CCA service;
- Requiring LSEs to include contract provisions for assignment to the POLR would risk unenforceability in bankruptcy, increased customer costs, and unintended market consequences; and
- A Commission-regulated public benefit central entity is a better long-term solution for POLR service, reliability and other critical functions.

II. THE COMMISSION SHOULD ENSURE THE BALANCE AND ACCURACY IN THE FSR CALCULATION RATHER THAN REPLACE THE FSR WITH AN OUT-SIZED LIQUIDITY POOL

Pacific Gas and Electric Company's (PG&E) comments focus primarily on its "procurement pool" proposal that would require each CCA to contribute an amount equal to its estimated costs during the two highest energy load months to provide the POLR with access to upfront liquidity in advance of customer transition to the POLR. Across the three IOUs, the pool size would range between $800 million to $1.4 billion.[8] Of that amount, PG&E's share would range from $415 million to $987 million.[9] Notably, neither SCE nor SDG&E raise similar concerns or proposals.[10] Based upon PG&E's comments, it appears the real issue driving PG&E's need for liquidity is the borrowing costs for the immediate California Independent

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8 Dependent on whether the pool is inclusive of energy only or energy, Resource Adequacy (RA), Renewable Portfolio Standard (RPS), and Administrative fees.

9 Based upon calculations provided by PG&E directly to CalCCA ($415 million) for energy only, and an estimate calculated by CalCCA for energy, RA, RPS, and Administrative fees.

10 *Opening Comments of Southern California Edison Company (U 338-E) on the Administrative Law Judge's Ruling Distributing Workshop Agenda and Providing Questions for Additional Post Workshop Comments,* R.21-03-011 (Mar. 28, 2022) (SCE Comments), at 16: In response to the question, "What options are available to provide sufficient cash flow for a mass transfer of customers to the POLR? What options other than significant cash flow are available to the POLR in the event of a mass transfer of customers?" SCE states, "Timely recovery of Re-Entry Fees is critical to ensuring sufficient cash flow in a mass involuntary return, including residual Re-Entry Fees that are authorized for recovery through a Tier 2 advice letter pursuant to Resolution E-5059." SCE does not mention a pool concept in response to this question but rather discusses the recovery of the re-entry fee in a timely manner.

System Operator Corporation (CAISO) energy costs of serving returning customers.[11] However, PG&E does not justify the assertion that it will not be able to borrow to pay for these costs in the event of customer return. In fact, PG&E notes that if the pool is not fully replenished by the revenues from returning customers, PG&E would amortize those funds with interest at the Federal Reserve's three-month Commercial Paper rate to be paid over time by returning customers.[12] While PG&E discusses the challenges of borrowing on short notice,[13] this information does not confirm that the POLR will be unable to find adequate credit facilities upon customer return to the POLR. More importantly, it does nothing to calibrate the risk of a large-scale return and the size of the pool. Any consideration of a pool must consider the relative risk and size of such a pool and the costs of acquiring the instruments necessary to fund the pool. The costs and feasibility of a pool must be compared with the costs and feasibility of relying on existing balancing account treatment for a two-month period.

CalCCA maintains, as discussed in Opening Comments,[14] that the right approach is ensuring the balance and accuracy in the FSR calculation and relying on existing balancing account treatment for any two-month periods while the IOU waits for revenues. Instead of continuing to develop an instrument whose need is undemonstrated and unproven, the Commission should focus on modifying the FSR to make it more accurate. Several parties have already commented on the need to more accurately identify the costs and revenues that impact

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11 *Opening Comments of Pacific Gas and Electric Company (U 39 E) on Administrative Law Judge's Ruling Distributing Workshop Agenda and Providing Questions for Additional Post Workshop Comments,* R.21-03-011 (Mar. 28, 2022) (PG&E Comments), at 6-8.

12 *Id.* at 11-12.

13 *Id.*, Appendix at 2.

14 *California Community Choice Association's Comments on Administrative Law Judge's Ruling Distributing Workshop Agenda and Providing Questions for Additional Post Workshop Comments*, R.21-03-011 (Mar. 28, 2022) (CalCCA Comments), at 5-11.

the FSR.[15] Further, as indicated in footnote ten, SCE has indicated that timely calculation and payment of the re-entry fee, which is based on the FSR calculation, is a significant step in ensuring that the POLR can serve returning customers. As such, the Commission should examine all of the FSR modifications raised in comments in this proceeding. This should include reductions in the quantity of RPS and RA for any returning Voluntary Allocation and Market Offer (VAMO) allocations and Cost Allocation Mechanism (CAM)[16] resources. This should also include updating the RA and RPS benchmarks to include the impacts of the returning customers' rate classes, reflect the impacts of any already authorized future rate changes, and account for the impact of seasonality of rates that returning customers will pay.

A. The Definition of Risks Should Include Not Only the Consequence but Also the Probability of the Outcome

Proposals to manage risk must weigh both the probability of an event as well as its consequences. Within this proceeding, the weighting of probability has been set at 100 percent. That is, assume the event will occur – the failure of a large LSE or the possibility of multiple concurrent LSE failures due to a major market shortage[17] -- then assess the consequences and how they are securitized. People and businesses do not hedge risk in this manner. Rather they account for the probability of the risk occurring and adjust their risk management accounting for the risk of the consequences coming to pass.

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15 *See* CalCCA Comments at 6-10; SCE Comments at 11-12; and SDG&E Comments at 8-9.

16 In response to the question, "Could the existing Capacity Allocation Mechanism (CAM) and Voluntary Allocation and Market Offer (VAMO) resources be used to meet POLR needs, and if so how?" SCE states, "Yes. These mechanisms are load-based and enable allocations to migrate along with migrating load. Thus, when an LSE fails and mass involuntarily returns its customers to the POLR, that LSE's CAM and VAMO allocations, as well as Demand Response (DR) related RA allocations, should / will migrate to the POLR, increasing the POLR's ability to close any gap on procurement needs to serve the mass involuntarily returned customers."

17 CPUC Energy Division Staff Presentation, October 29, 2021, at 93.

PG&E has proposed a posting requirement equal to the anticipated cost of energy at the CAISO for two months. While PG&E does indicate that costs of posting may be higher under its proposal, the probability that PG&E will need to procure in such a circumstance is absent from the calculation. CalCCA has estimated the cost of two months CAISO energy costs at approximately $800 million for all CCAs.[18] This represents the cost that would be anticipated to be incurred if all CCAs returned their load to POLR service. It fails to account for the very likely event that not all or even a significant portion of CCAs will fail. Indeed, according to the Texas Public Utilities Commission, even under the winter of 2021 events, only three Retail Electric Providers (REP) exited the business with a fourth entering bankruptcy.[19] At present, Texas lists over 150 REPs.[20] The event in Texas saw market prices exceeding the price caps applicable in the CAISO market by a significant margin. The U.S. Energy Information Administration (EIA) reports prices at or near $9,000 MWh for 77 hours over four days.[21] The CAISO market bids are capped at $2,000 MWh. Even in these extreme price events in Texas, a small number of REPs exited the market.

Failing to account for the probability of an event will significantly over-securitize the risk at the expense of customers. Presently a CCA may post a letter of credit, cash, or a surety bond with the IOU for the FSR. Each has cost consequences for customers. In addition, both a secured letter of credit (LOC) and cash limit the LSE's liquidity; a secured LOC limits the LSE's borrowing ability, and cash limits other uses of the cash. Taken to an extreme, these limitations

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18 CalCCA previously reported its estimate of the CCA pool concept at $1.4 Billion. This estimate was based upon Energy, RPS, RA, and Administrative costs as calculated by the FSR today. Excluding RPS, RA, and Administrative costs, the estimate is approximately $800 million for all CCAs.

19 https://www.puc.texas.gov/agency/resources/reports/UTAustin_(2021)_EventsFebruary2021TexasBlackout_(002)FINAL_07_12_21.pdf, at 90.

20 https://www.puc.texas.gov/industry/electric/directories/rep/alpha_rep.aspx.

21 https://www.eia.gov/todayinenergy/detail.php?id=47876.

could affect an LSE's ability to advance clean energy resource development. The only instrument that does not have this effect is a surety bond, which SCE now proposes to eliminate as an option, as discussed below.

Consider the effect of the use of letters of credit to fund a liquidity pool of the magnitude PG&E proposes. A secured LOC may have costs as low as 65 basis points annually, the securitization means encumbering cash with the financial institution providing the letter. Therefore, if used by all CCAs, $800 million in cash would be encumbered that would be better spent developing new non-emitting resources to meet grid and policy goal needs. In addition to the opportunity cost of the posted cash, it would also cost CCA customers in excess of $5 million annually. Unsecured instruments such as a surety bond or unsecured LOC may cost the borrowing entity on the order of 200 basis points. This would reduce the liquidity crunch from setting aside millions of dollars as security, but it would come at a cost of $16 million per year for the same $800 million in security. Since these costs accumulate each year, over the next 20 years alone the additional costs would be between $100 million and $320 million. This is an unreasonable price for customers to pay for an event that is unlikely to occur.

PG&E's liquidity proposal must be viewed through the lens of not only consequences, but probability of failure. As CalCCA has noted, seven CCAs now have investment-grade credit ratings, with two ratings that were issued *after* the WCE bankruptcy. This means that a ratings agency has issued an opinion about the ability and willingness of an entity to meet its financial obligations in full and on time.[22] In addition, all CCAs have active risk management policies, which are publicly available, and conduct risk oversight on a regular basis. Risk management mitigates the risk of default – both the probability and potential consequences of failure.

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22 https://www.spglobal.com/ratings/_division-assets/pdfs/guide_to_credit_rating_essentials_digital.pdf, at 4.

B. SCE and SDG&E's Proposed FSR Changes are Imbalanced and Require Additional Changes to Improve the Accuracy of the Calculation

SCE and SDG&E each propose two changes to the FSR calculation to improve its accuracy. First, they propose the calculation of RA and RPS costs should use the most up-to-date benchmarks.[23] CalCCA agrees with this change.[24] Additionally, SCE proposes the FSR and re-entry fee calculation must net "the PCIA revenues the IOUs expects to recover from the mass involuntary returning CCA customers over the forward six-month period from the gross revenues the IOU expects to recover from those customers over the same period."[25] SDG&E also suggests the FSR calculation needs to be revised to consider Power Charge Indifference Adjustment (PCIA) rates already received by the IOU that would not be incremental revenue.[26]

If the Commission moves forward with changes to the FSR calculation to improve its accuracy, the Commission should take a holistic review of the calculation to ensure each component of the calculation is properly updated. Therefore, in addition to reconsidering the benchmarks for RA and RPS costs and the treatment of PCIA revenues, the Commission should also consider the changes proposed by CalCCA, including (1) accounting for resources readily available to the POLR (*i.e.*, CAM and Voluntarily Allocated PCIA); (2) updating the RA and RPS benchmarks to include the impacts of the returning customers' rate classes; (3) reflecting the impacts of any already authorized future rate changes; and (4) accounting for the impact of seasonality of rates that returning customers will pay.[27] This will ensure that cost and revenue forecasts are equally informed for all elements.

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23 SCE Comments at 11; and SDG&E Comments at 11.
24 CalCCA Comments at 7.
25 SCE Comments at 12.
26 SDG&E Comments at 8.
27 CalCCA Comments at 8-9.

C. The Need to Remove Surety Bonds as a Security Instrument has not Been Sufficiently Demonstrated

The Commission should not remove surety bonds as a security instrument to comply with the FSR. The FSR statute expressly allows for posting a bond.[28] The Commission appropriately allowed for surety bonds when implementing the statute with respect to CCAs.[29] SCE proposes to remove surety bonds as an instrument that can be used to meet a CCA's FSR. SCE bases this proposal on the supposition that "they [surety bonds] are expected to be litigious, just as insurance claims typically are, and can potentially take months or years for the IOU to recover on its Re-Entry Fee claim and impact the IOUs' liquidity during this period of dispute." [30] However, the Commission expressly rejected this argument:

The Joint Utilities describe the problem with surety bonds as follows:

> Collecting on a surety bond is similar to collecting on an insurance claim, where a litigious and delayed process for resolving a claim is not unusual.... The purpose of the statute appears to be more about basic financial security – ensuring that money is available – rather than liquidity. The fact that surety bonds may not be commonly used for other purposes in the energy procurement business does not control in this context, where there is express statutory language. Accordingly, we approve the use of surety bonds as FSR for CCAs.[31]

The governing statute permitting a bond - section 394.25(e) – has not changed and continues to permit the use of a bond. SCE's supposition was not sufficient when raised before the Commission previously, and it is not sufficient now to remove surety bonds as an option. As noted in section II.A, a surety bond may be the most cost-effective manner of meeting an FSR

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28 Cal. Pub. Util. Code § 394.25(e).
29 D.18-05-002 Ordering Paragraph 7.
30 SCE Comments at 16.
31 D.18-05-022 at 8-9.

requirement to avoid encumbering needed cash. For these reasons, the Commission should reject SCE's proposal.

III. ANY FINANCIAL MONITORING MUST MAKE USE OF EXISTING PUBLIC INFORMATION AND SHOULD BE AIMED SOLELY AT PROVIDING THE COMMISSION ADVANCE NOTICE OF LIKELY CUSTOMER RETURNS

Parties have made a number of financial monitoring proposals, including monitoring based upon publicly available data,[32] complex monitoring using a substantial list of metrics,[33] required use of a third-party credit rating agency,[34] and preemptive action to deregister an LSE involuntarily in response to unspecified financial circumstances.[35] CalCCA's proposal would (1) enhance the implementation planning process for newly launching CCAs; and (2) require financial monitoring of existing LSEs, including CCAs and ESPs, using publicly available data based on a tiered approach that considers each LSE's circumstance. Any financial monitoring proposal adopted should strike a reasonable balance between the ability for the Commission to evaluate useful information, and the ability for the LSE to provide the information without the need to disclose confidential information or report unnecessary information. CalCCA's proposal does this by providing the Commission the information it needs to be informed of LSE's financial activities, leveraging publicly available information, and ensuring LSEs can readily provide the necessary information.

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32 CalCCA Comments at 16-18.

33 *Comments of the Public Advocates Office on the Administrative Law Judge's Ruling Distributing Workshop Agenda and Providing Questions for Additional Post Workshop Comments,* R.21-03-011 (Mar. 28, 2022), at 11-19; and PG&E Comments at 21-23.

34 SDG&E Comments at 21-23.

35 SCE Comments at 2.

D. The Commission Should Develop an Administratively Simple Approach to Financial Monitoring as Opposed to a Complex Approach Resulting in Premature Action by the Commission

The Public Advocates Office (CalAdvocates) and PG&E propose a significant number of metrics CCAs should report to the Commission. At this point, however, the Commission should avoid undertaking an overly complex oversight framework for CCA financial practices. Instead, the Commission should develop administratively simple approaches to identify financially stressed LSEs and engage those LSEs in consultation to better understand their plans going forward.

Further, as discussed in section VI, it is not within the scope of the Commission's jurisdiction to terminate LSE service involuntarily, as suggested by SCE. It should be noted that pre-emptive action was not taken in either of the bankruptcies of PG&E, and yet customers continued to be served. It is possible that a similar event could occur with a CCA or Electric Service Provider (ESP), where the LSE continues service following bankruptcy. If the Commission took pre-emptive action, the ability to continue to serve those customers by the CCA or ESP would be removed unnecessarily. Such an outcome would result in significant market disruption and undermine confidence in the stability of the business environment in California.

CalCCA's proposal for financial oversight serves as a reasonable basis for the Commission to begin to understand the mechanisms and practices used by different LSEs while remaining clearly within the Commission's jurisdiction.[36]

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36 CalCCA Comments at 16-18.

E. The Commission Should not Require all CCAs to Obtain a Credit Rating

The Commission should dismiss any suggestions that all CCAs must pursue a compulsory credit rating. SDG&E suggests "[t]he most critical new measure to be implemented at this point is the requirement that all CCAs (*i.e.*, those currently in existence and those that form in the future) register with third party credit rating agencies (*e.g.*, Moody's Investors Service, S&P Global Ratings (Standard & Poor's))."[37] The Commission should not adopt this proposal given the undue burden it would place on smaller or newly forming LSEs. Obtaining a credit rating by an independent agency is costly and requires an extreme amount of time and effort that may be too burdensome for smaller or newly formed LSEs. In addition, forcing newly launched CCAs to get credit ratings before they are ready and have established an operating history is very likely to increase the costs for new CCAs both in (1) staff time and direct costs to work with rating agencies; and (2) higher procurement costs across the board. The Commission must balance the burden on LSEs associated with financial monitoring with the benefit of having the information. Requiring credit ratings of all CCAs would be unduly burdensome, particularly when the Commission can obtain valuable information through the reporting as suggested by CalCCA.

Rather than requiring CCAs to be credit rated, the Commission should adopt CalCCA's proposed tiers, which would require different levels of financial monitoring based on individual LSE's circumstances, including if the LSE is credit-rated. Under CalCCA's tier proposal, if the LSE has an investment-grade credit rating, no additional financial monitoring would be required. This would provide incentives for LSEs to obtain credit ratings, while providing smaller LSEs the option to forego obtaining a credit rating in favor of financial monitoring. This proposal recognizes that credit-rated LSEs are already under evaluation by a third-party that specializes in

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[37] SDG&E Comments at 22.

evaluating entities' financial health and recognizes that entities with investment-grade credit ratings are extremely unlikely to fail, as demonstrated in Table 1 below.

Standard & Poor's *Default, Transition, and Recovery: 2020 Annual Global Corporate Default and Rating Transition Study* provides metrics around the default rates of credit-rated entities, indicating investment-grade credit-rated entities have a very low probability of default.[38]

Global Corporate Average Cumulative Default Rates By Rating Modifier (1981-2020) (%)

	--Time horizon (years)--														
Rating	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**
AAA	0.00	0.03	0.13	0.24	0.34	0.45	0.51	0.59	0.64	0.70	0.72	0.75	0.78	0.84	0.90
AA+	0.00	0.05	0.05	0.10	0.15	0.20	0.25	0.31	0.36	0.42	0.48	0.53	0.59	0.66	0.72
AA	0.02	0.03	0.08	0.21	0.35	0.47	0.59	0.70	0.78	0.87	0.95	1.00	1.10	1.16	1.22
AA-	0.03	0.08	0.16	0.23	0.31	0.41	0.47	0.52	0.57	0.62	0.68	0.73	0.75	0.80	0.84
A+	0.05	0.09	0.19	0.31	0.41	0.50	0.60	0.71	0.83	0.96	1.08	1.21	1.36	1.54	1.68
A	0.05	0.14	0.21	0.32	0.44	0.61	0.78	0.94	1.11	1.32	1.48	1.60	1.72	1.79	1.95
A-	0.06	0.16	0.25	0.36	0.51	0.66	0.87	1.03	1.15	1.27	1.37	1.50	1.62	1.74	1.84
BBB+	0.09	0.26	0.47	0.67	0.90	1.15	1.35	1.56	1.82	2.07	2.30	2.46	2.64	2.87	3.12
BBB	0.15	0.37	0.59	0.93	1.27	1.62	1.94	2.24	2.56	2.88	3.22	3.49	3.72	3.82	4.03
BBB-	0.24	0.69	1.27	1.93	2.63	3.24	3.78	4.28	4.69	5.04	5.43	5.75	6.05	6.51	6.86
BB+	0.32	0.97	1.76	2.55	3.35	4.14	4.82	5.32	5.92	6.52	6.93	7.42	7.92	8.27	8.82
BB	0.48	1.52	2.96	4.34	5.76	6.88	7.92	8.81	9.67	10.43	11.25	11.86	12.34	12.68	13.0
BB-	0.96	2.92	5.01	7.15	9.03	10.83	12.34	13.78	14.92	15.92	16.68	17.46	18.21	18.94	19.6
B+	1.98	5.42	8.82	11.73	14.02	15.80	17.43	18.86	20.17	21.37	22.41	23.14	23.92	24.65	25.3
B	3.13	7.35	11.11	14.19	16.69	18.97	20.62	21.87	23.07	24.26	25.02	25.78	26.37	26.89	27.4
B-	6.52	13.69	19.28	23.16	25.97	28.07	29.63	30.86	31.72	32.45	33.61	34.32	34.89	35.46	35.8
CCC/C	28.30	38.33	43.42	46.36	48.58	49.61	50.75	51.49	52.16	52.76	53.21	53.68	54.23	54.69	54.7
Investment grade	0.09	0.24	0.41	0.63	0.86	1.09	1.30	1.50	1.69	1.88	2.05	2.20	2.35	2.49	2.65
Speculative grade	3.71	7.19	10.18	12.63	14.64	16.30	17.68	18.83	19.86	20.81	21.61	22.29	22.93	23.49	24.0
All rated	1.53	3.00	4.27	5.35	6.25	7.01	7.64	8.18	8.67	9.12	9.50	9.83	10.13	10.41	10.6

Sources: S&P Global Ratings Research and S&P Global Market Intelligence's CreditPro®.

[38] *Default, Transition, and Recovery: 2020 Annual Global Corporate Default and Rating Transition Study* at Table 26: https://www.spglobal.com/ratings/en/research/articles/210407-default-transition-and-recovery-2020-annual-global-corporate-default-and-rating-transition-study-11900573.

Given the very low probability of default by investment grade credit rated entities it is reasonable for the Commission to require additional financial monitoring of LSEs without investment-grade credit ratings using publicly available information to allow the Commission to gather information about the health of LSEs and to inform the Commission of when LSE consultations are needed. This approach would not be overly burdensome and would provide the Commission useful information needed to gain insight into the financial conditions of all LSEs. For these reasons, the Commission should adopt CalCCA's proposal for tiered financial monitoring rather than require all CCAs obtain a credit rating as SDG&E proposes.

F. The Commission Must Apply Financial Monitoring and Risk Management Requirements Comparably Between CCAs and ESPs

DAC/UC/AReM's comments suggest financial monitoring and risk management proposals should apply to CCAs only.[39] In part, DAC/UC/AReM's argument is that ESPs are large multi-national companies and that there is a robust market for the provision of direct access. Neither of these arguments hold true under a "Black Swan" event the Commission is preparing for through this proceeding. The size and scope of a business does not guarantee that they will take losses to serve customers. If the profit from one market is reduced, entities will tend to invest that capital in a market with better returns. Under a market environment with high energy and capacity costs, there is no reason to believe that an ESP would continue to take losses by continuing to serve its customers. At the same time, if one ESP fails during a price spike, while other ESPs may continue to exist, it may not be feasible for them to take on new customers from the failed ESP at high prices when the customers have the option of returning to the IOU service. This was reported to have happened in Texas where an ESP encouraged customers to

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[39] *Comments of the Direct Access Customer Coalition, the Regents of the University of California and Alliance For Retail Energy Markets on Ruling Providing Questions for Additional Post Workshop Comments,* R.21-03-011 (Mar. 28, 2022) (DAC/UC/AReM Comments), at 3-5.

leave its service but other ESPs were not taking on new customers due to the volatility in pricing.[40] Given the Commission's problem statement in this proceeding is rooted in extreme events, and the fact that market price volatility will impact all LSEs and not just CCAs, proposals should apply to CCAs and ESPs alike.

IV. THE LEGISLATURE DID NOT AUTHORIZE THE COMMISSION TO UNILATERALLY TERMINATE CCA SERVICE

As CalCCA explains in section III, the Commission should limit any financial monitoring of LSEs to a purpose squarely within its statutory authority. SCE's comments clearly articulate this purpose: "to see early warning signs and influence the processes and outcomes in the event of an LSE failure is imminent and unavoidable." SCE unfortunately encourages the Commission to take a step outside of its jurisdiction, suggesting that "the Commission should be prepared to take pre-emptive actions, such as involuntary LSE service terminations when there is good cause, to protect customers."[41] The Commission should reject SCE's proposal and ensure any financial monitoring remains within the clear scope of its jurisdiction.

Assembly Bill (AB) 117 (2002)[42] established the primary scope of the Commission's jurisdictional authority.[43] Nothing in the bill allows the Commission to financially monitor or, more importantly, terminate a CCA's registration based on this monitoring. The primary focus of the Commission's role as established in AB 117 was "to determine a cost-recovery mechanism to be imposed on the community choice aggregator to prevent a shifting of costs to an electrical

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40 https://www.dallasnews.com/business/energy/2021/02/16/electricity-retailer-griddys-unusual-plea-to-texas-customers-leave-now-before-you-get-a-big-bill/.

41 SCE Comments at 2.

42 Assembly Bill 117 (Migden 2002) (Electrical Restructuring: aggregation).

43 Since AB 117's enactment, the Commission's role has been expanded to limited authority related to Resource Adequacy (Cal. Pub. Util. Code § 380) and renewable resource integration (Cal. Pub. Util. Code § 399.12(j)(2)).

corporation's bundled customers."[44] Moreover, nothing in the list of required information for the implementation plan touches on the CCA's financial condition.[45] Finally, while the Commission may request additional information in some cases, requesting information is a far cry from revoking registration.[46]While the Legislature did not grant the Commission authority to assess or act on CCA financial condition, it expressly provided the Commission with that authority for ESPs. The Commission must require as a condition of registration "proof of financial viability" assessed using "uniform standards."[47] The Legislature also expressly and clearly provided the Commission authority to suspend or revoke an ESP's registration, "in whole or in part," under several circumstances. Most notably, the Commission may revoke or suspend an ESP's registration when "there is evidence that the electric service provider is not financially or operationally capable of providing the offered electric service."[48] None of these very explicit statutory directives applies to CCAs.

SB 520, enacted in 2019, did not extend the Commission's authority over CCAs. The primary focus of the bill is to describe the characteristics required for an entity to serve as POLR. In fact, the only provisions addressing entities *other than* a POLR address "continued achievement of California's greenhouse gas emission reduction and air quality goals."[49] Nothing in the Legislature's POLR directives give the Commission authority to terminate the registration of a CCA.

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[44] AB 117 Legislative Digest (1). The bill also addressed CCA participation in energy efficiency programs. *See* Cal. Pub. Util. Code § 381.1.
[45] *See* Cal. Pub. Util. Code § 366.2(c)(3).
[46] *Id.* at (c)(17).
[47] *See* Cal. Pub. Util. Code § 394.25(b)(9).
[48] *Id.* at (b)(3).
[49] Cal. Pub. Util. Code § 387(h).

AB 117 expressly establishes a role for the Commission in the implementation process. Other than the roles carved out for oversight of RA compliance and renewable integration purposes, the Legislature left financial and rate oversight to the local governing body. The Commission thus should reject SCE's proposal to step across the jurisdictional boundary to unilaterally terminate a CCA's registration.

V. REQUIRING LSES TO INCLUDE CONTRACT PROVISIONS FOR ASSIGNMENT TO THE POLR WOULD RISK UNENFORCEABILITY IN BANKRUPTCY, INCREASED CUSTOMER COSTS, AND UNINTENDED MARKET CONSEQUENCES

Early in this proceeding, Commission staff raised the possibility of assigning contracts of a failing LSE to the POLR upon customer return.[50] Certain parties continue to support this concept, including the California Energy Storage Alliance (CESA), the Solar Energy Industries Association (SEIA) and the Large-scale Solar Association (LSA) (SEIA/LSA), and Small Business Utility Advocates (SBUA).

CESA and SEIA/LSA suggest *mandatory* novation of contracts to the POLR upon a return of customers. They suggest this tool could lower financing costs by providing more certainty to financers that the contract will remain intact in the event of an LSE deregistration.[51] SEIA/LSA's novation proposal would apply only to CCAs and explicitly exclude ESPs.[52] Such an exclusion would be arbitrary and further distort market conditions by putting CCAs on an unequal playing field with ESPs and IOUs. The Commission should not adopt requirements for one set of LSE contract while not requiring the same of other LSEs. No other party – notably including the IOU POLRs – support the SEIA/LSA solution. The IOUs do not support

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[50] *Administrative Law Judge's Ruling Directing Further Party Comment, Requesting Party Proposals, and Amending Procedural Schedule*, R.21-03-011 (Nov. 23, 2021), Attachment 2, at 3.

[51] SEIA/LSA Comments at 7.

[52] CESA Comments at 3.

mandatory assignment, noting that (1) the contracts were not reviewed for reasonableness by the Commission, "run[ning] afoul of the Commission's statutory duty to ensure that IOU rates are just and reasonable;[53] (2) because the POLR would play no role in negotiation, the contract terms and provisions may be unacceptable to the POLR;[54] and (3) mandatory contract assignment could increase stranded cost risk given the POLR may not need the contracts from the returning LSE.[55]

Given their concerns around mandatory contract assignment, the IOUs suggest any assignment of contracts to the POLR should be *voluntary*. Other parties, including CalAdvocates and Utility Consumers' Action Network (UCAN), support the inclusion of right of first refusal (ROFR) clauses into contracts. The Commission should not adopt requirements to include voluntary contract assignment provisions or ROFRs. Adopting such a requirement could have significant cost impacts on existing and future contracts in order to prepare for an event unlikely to occur in the first place. This is due, in part, to the need to underwrite the contract based on the credit risk of both counterparties. PG&E is the designated POLR for its service area and has maintained non-investment credit ratings since it entered bankruptcy. Further, as explained in CalCCA's opening comments and in the workshop, it is unlikely these provisions would be upheld in bankruptcy court.

The Utility Reform Network (TURN) suggests that in lieu of contract assignment, the Commission should consider a requirement that LSEs perform hedging of capacity and energy covering at least 6-12 months that can be transferred to the POLR in the event of a default.[56]

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53 SCE Comments at 3.

54 SDG&E Comments at 3.

55 PG&E Comments at 16.

56 *Comments of The Utility Reform Network on the March 7 Workshop and Responses to Questions in the February 24, 2022 Ruling of Administrative Law Judge Hecht*, R.21-03-011 (Mar. 28, 2022) (TURN Comments), at 7.

"Transfer" is just another word for "assign." Despite TURN's assertion that, "[t]ransferable short-term hedges could be less complex than requiring ROFRs for long term contracts,"[57] the process would be no less complex and no more likely to survive bankruptcy than any other assignment of a contract that inherently has value. For this reason, TURN's proposal should be rejected.

For all these reasons, the Commission should not adopt long-term procurement contract or short-term hedge assignment, whether voluntary or involuntary.

VI. A COMMISSION-REGULATED PUBLIC BENEFIT CENTRAL ENTITY IS A BETTER LONG-TERM SOLUTION FOR POLR SERVICE, RELIABILITY AND OTHER CRITICAL FUNCTIONS

In its comments, TURN "supports consideration of alternative POLR structures including the development of a statewide nonprofit entity that could assume this responsibility."[58] CalCCA agrees with TURN. The Commission should explore a central entity regulated by the Commission that could provide POLR service as well as other reliability functions such as local RA procurement (currently performed by PG&E and SCE), system and flexible RA procurement, and provision of default service. Such an entity, which likely would require legislation, may better ensure competitive neutrality and remove burdens from the IOUs for central procurement.

Indeed, PG&E's comments highlight concerns with placing PG&E in the POLR position. In Appendix A of its comments, PG&E lists three factors that may limit their ability to access capital:

1. Quarterly earnings blackout
2. Limit on the amount of borrowing available and/or authorized

57 TURN Comments at 7.
58 *Id.*

3. Financial market conditions

The first two factors point to a conflict between providing POLR service as an IOU. The IOU as a vertically integrated, for-profit entity has many demands upon its finances. These include infrastructure build, operational needs, and research and development funding, among others. A for-profit entity would rather use its financial capacity to earn a return for investors, and POLR service does not produce a return. In contrast, a centralized public benefits corporation subject to Commission regulation could instead focus on central procurement using resources unencumbered by other demands. For these reasons, the Commission should expedite Phase 2 of this proceeding, where the Commission will consider entities other than the IOUs as POLR.

VII. CONCLUSION

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

Respectfully submitted,

Evelyn Kahl

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CALIFORNIA COMMUNITY CHOICE ASSOCIATION

April 15, 2022

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

Order Instituting Rulemaking to Continue Electric Integrated Resource Planning and Related Procurement Processes.	R.20-05-003

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS
ON THE PROPOSED DECISION ON MODIFIED COST ALLOCATION MECHANISM
FOR OPT-OUT AND BACKSTOP PROCUREMENT OBLIGATIONS**

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April 18, 2022

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SUMMARY OF RECOMMENDATIONS

SPECIFICATION OF ERROR

1. The proposed Decision on Modified Cost Allocation Mechanism for Opt-Out and Backstop Procurement Obligations (PD or Proposed Decision) erroneously relies on Public Utilities Code sections 365.1(c)(2) and 454.51(c) to conclude that the modified cost adjustment mechanism (MCAM) must include a non-bypassable customer charge;

2. The Proposed Decision worsens billing distortions and places self-procuring load-serving entities (LSEs) at a competitive disadvantage by embedding the above-market costs for bundled and opt-out and backstop LSEs in the distribution rate component of a customer's bill;

3. The Proposed Decision unjustifiably increases complexity and costs of investor-owned utility (IOU) billing by incorporating the MCAM into investor-owned utility (IOU) rates rather than directly billing responsible LSEs; and

4. The Proposed Decision fails to address the significant costs that can accrue to remaining customers when customers migrate from a bundled or opt-out/backstop LSE to another LSE.

RECOMMENDED CHANGES

1. The Proposed Decision should be modified to require billing of opt-out and backstop procurement costs directly to the LSEs responsible for such costs; and

2. If the Commission adopts the Proposed Decision's MCAM methodology to bill customers rather than LSEs directly, the Commission should: (a) move the above-market costs to the generation portion of the IOU bill (along with the Market Price Benchmark (MPB) costs) to prevent billing distortions that place self-procuring LSEs at a competitive disadvantage; (b) require the tagging and tracking of migrating customers to ensure such customers continue to be held responsible for the costs of procurement on their behalf; and (c) clarify that the MCAM will only be applied in situations in which IOUs, other LSE types, or other entities are required to procure on behalf of some, but not all, LSEs.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Electric Integrated Resource Planning and Related Procurement Processes.	R.20-05-003

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION ON MODIFIED COST ALLOCATION MECHANISM FOR OPT-OUT AND BACKSTOP PROCUREMENT OBLIGATIONS

The California Community Choice Association (CalCCA)[1] submits these comments pursuant to Rule 14.3 of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure on the proposed *Decision on Modified Cost Allocation Mechanism for Opt-Out and Backstop Procurement Obligations* (PD or Proposed Decision), issued on March 29, 2022.

I. INTRODUCTION

The procurement ordered by the Commission in Decisions (D.) 19-11-016 and D.21-06-035 fulfills specific system reliability needs over the short and mid-term, and advances the Commission's "preference" that LSEs, including community choice aggregators (CCAs) and electric service providers (ESPs), self-procure their allocated share.[2] All but 113 megawatts

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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 D.19-11-016, *Decision Requiring Electric System Reliability Procurement for 2021-2023,* R.16-02-007 (Nov. 13, 2019) at 37; D.21-06-035, *Decision Requiring Procurement to Address Mid-Term Reliability (2023-2026),* R.20-05-003 (Jun. 30, 2021).

(MW) of the 3,300 MW capacity obligations allocated in D.19-11-016 to the IOUs, LSEs, and Electric Service Providers (ESP) was self-procured, with 11 LSEs opting out of self-procurement, including ESPs and two very small CCAs.[3] For those that opt out, or who commit to self-procure but then fail and require IOUs to "backstop" their procurement, the PD adopts a cost allocation mechanism, the MCAM, for IOUs to recover their net costs of procurement. Instead of requiring direct billing of the opt-out or backstop costs by the IOU to the responsible LSE, as CalCCA recommended, the PD directs the use of a non-bypassable customer charge for the IOUs' above-market costs. The PD proposes to have the above-market costs be added as a separate component of the distribution rate for customers of bundled and opt-out LSEs. LSEs that self-procure, however, will not have the option of including such costs in the distribution rate, but rather will include all such costs in their generation rate, resulting in billing distortions that will cause self-procuring LSEs' generation rates to appear higher. Even if the separate charge carries an explanatory annotation, the Commission cannot reasonably expect customers to understand the issue or correctly compare rates.

The PD admits that from a policy perspective, direct billing of responsible LSEs "would put responsibility for the management decisions of the LSE where it belongs, on the management of the LSE," and that direct billing would be easier and less costly to implement.[4] However, the Commission bases its decision that customers must be charged (rather than LSEs) on a flawed reading of Public Utilities Code sections 365.1(c)(2) and 454.51(c). Section 365.1(c)(2) only applies when the IOU procures on behalf of <u>all</u> LSEs, and therefore does not apply in the MCAM situation where the IOU has procured on behalf of only <u>some</u> LSEs. Section 454.51(c) applies to

[3] Proposed Decision at 2; *Administrative Law Judge's Ruling Seeking Comments on Backstop Procurement and Cost Allocation Mechanisms,* R.20-05-003 (Apr. 15, 2020) (April 15, 2020 ALJ Ruling), at 9.

[4] Proposed Decision at 17.

renewable energy integration resources, when the applicability of the MCAM relates to procurement based on system reliability.

In proposing to establish the MCAM as a nonbypassable customer charge, the PD errs by:

- ✗ Worsening billing distortions and placing self-procuring LSEs at a competitive disadvantage by embedding the above-market costs for bundled and opt-out and backstop LSEs in the distribution rate component of a customer's bill;
- ✗ Unjustifiably increasing complexity and costs of IOU billing by incorporating the MCAM into IOU rates rather than directly billing responsible LSEs;
- ✗ Failing to address the significant costs that can accrue to remaining customers when customers migrate from bundled or opt-out/backstop LSEs to another LSE; and
- ✗ Erroneously relying on Public Utilities Code sections 365.1(c)(2) and 454.51(c) to conclude that the MCAM must include a non-bypassable customer charge.

The Commission should modify the PD by requiring direct billing of opt-out and backstop procurement costs to the LSEs responsible for such costs.

If, despite CalCCA's recommendations above, the Commission adopts the PD's MCAM methodology to bill customers rather than LSEs directly, the Commission should:

- ✓ Move the above-market costs of the procurement to the generation portion of the IOU bill (along with the MPB costs for attributes) to prevent billing distortions that make it impossible for customers to understand and place self-procuring LSEs at a competitive disadvantage;
- ✓ Require the tagging and tracking of migrating customers to ensure such customers continue to be held responsible for the costs of procurement on their behalf; and
- ✓ Clarify that the MCAM will only be applied in situations in which IOUs, other LSE types, or other entities are required to procure on behalf of some, but not all, LSEs.

II. THE COMMISSION SHOULD MODIFY THE PROPOSED DECISION TO REQUIRE DIRECT BILLING OF OPT-OUT AND BACKSTOP PROCUREMENT COSTS TO THE LSES RESPONSIBLE FOR SUCH COSTS

The PD should be modified to require direct billing of opt-out and backstop procurement costs to the responsible LSEs, instead of billing customers. Even the PD recognizes the benefits of direct billing:

> In some ways it would be preferable, on a policy basis, to have the IOUs bill the appropriate LSEs directly for either opt-out or backstop procurement. This would put responsibility for the management decisions of the LSE where it belongs, on the management of the LSE. LSEs who opted out or failed to procure capacity would be responsible for their own costs and approach to collecting the associated costs. In addition, this would be far easier to implement, because it would involve a direct contractual obligation between LSEs, with no requirement for billing system changes or the complexity of tracking customers over long periods of time by the IOUs.[5]

As set forth below, directly billing opt-out and backstop procurement costs prevents the billing distortions and resulting competitive disadvantage for self-procuring LSEs that fulfilled the Commission's preference for LSE self-procurement. Direct billing also promotes administrative ease to implement the MCAM. Finally, the Commission's basis for requiring customer billing, Public Utilities Code sections 365.1(c)(2) and 454.51(c), are inapplicable to the MCAM and reliance on them rests on legal error.

A. Billing LSEs Rather Than Customers Avoids Further Distortions in Customer Billing and the Resulting Disincentives for Self-Procuring LSEs

Customer billing for purposes of MCAM results in customer confusion and a competitive disadvantage for self-procuring LSEs because of the resulting distortions to bill presentation. The PD attempts to lessen such bill distortions by directing the IOUs to apply the MPB portion of costs to the LSE's generation portion of the bill, and the above-market MCAM costs to the distribution portion (with a notation in the "fast lane" section of the bill listing the MCAM charges embedded in the distribution charge).[6] However, when customers looks at their bill, they will be unlikely to understand that the MCAM costs are actually a generation component. A self-procuring LSE will reflect its procurement of resources to meet the D.19-11-016 and D.21-06-035

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5 Proposed Decision at 17.

6 *Id.* at 50.

requirements in its generation component, where the costs rightly belong. Thus, if a customer were trying to compare generation costs, it could not. In addition, LSEs choosing to self-procure will appear to have higher generation costs than backstopped LSEs, because the latter will mask their costs in distribution charges.

The Commission in D.19-11-016 "implement[ed] a preference that each LSE, regardless of whether it is an IOU or an ESP or CCA, is responsible for its own share of the incremental reliability and renewable integration resources identified herein as needed."[7] In addition, the Commission stated that "[t]his is also an appropriate place to test how well the obligated LSEs perform when given a procurement requirement for system reliability and renewable integration resources in the context of IRP."[8] As noted above, eleven LSEs opted out of D.19-11-016 requirements, representing approximately 113 megawatts (MW) of the total 3,300 MW of required capacity.[9] The vast majority of CCAs self-procured, with large ESPs and two very small CCAs opting out of conducting their own resource adequacy (RA) requirements.[10]

D.19-11-016 also advanced the principle that the backstop mechanism "should not disincentivize self-procuring LSEs from being successful with their full procurement requirement."[11] Unfortunately, the PD does just that by leaving the LSEs that fulfilled the objectives of the Commission to contend with bill distortions that place them at a competitive disadvantage with customers. The PD therefore errs by embedding within the MCAM cost mechanism the disincentive to self-procure.

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7 D.19-11-016 at 37.
8 *Id.* at 39.
9 Proposed Decision at 2.
10 April 15, 2020 ALJ Ruling at 9.
11 *Id.* at 4 (summarizing the principles established by D.19-11-016).

B. Billing LSEs Rather Than Customers Simplifies Administration

Billing LSEs rather than their customers is a simple approach. Most, if not all LSEs already have Edison Electric Institute (EEI) Master Power Purchase and Sale Agreements in place with their respective IOUs, and regularly execute confirmations thereunder; RA transactions between IOUs and LSEs are commonplace. Confirmations are largely pro-forma and can be quickly negotiated, as needed. The leaning LSE will recover their costs through the generation rate billed to their customers in the same way a self-procuring LSE will recover its incremental procurement costs. This critical symmetry preserves competitive balance.

In contrast, the customer charge proposed in the PD requires extensive rate design and billing system changes (requiring additional costs). For example, Pacific Gas and Electric Company (PG&E) estimates that it will take 12-24 months to modify its billing system to accommodate the MCAM customer charges, at a cost of three to five million dollars.[12] Billing LSEs directly would avoid these additional costs and billing changes, promoting administrative simplicity and efficiency.

C. Billing LSEs Rather Than Customers Removes the Complexity Resulting from Load Migration and Mitigates the Risk of Cost Shifts

Directly billing LSEs avoids the problems associated with direct customer billing and potential customer migration to another LSE. The Proposed Decision recognizes the difficulties associated with holding customers accountable for the MCAM costs when they migrate, and that the remaining customers of the LSE losing load will pay a higher rate to cover the costs of the migrating customer.[13] However, the PD chooses not to hold migrating customers accountable for the costs, stating without further explanation or support that "the simplification that this approach

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[12] Proposed Decision at 27-28.
[13] *Ibid.*

allows outweighs the importance and costs of tracking individual customers for a minimum of ten years."[14] It is imperative that either the benefits and costs match or that LSEs are afforded the opportunity to transact the allocated resources to effectively meet customer needs and offset costs if their load migrates. Fundamentally, customers should pay for the benefits received regardless of which LSE serves their energy needs. The Cost Allocation Mechanism (CAM) meets this objective in that the costs and benefits move with the customers as they migrate. This objective is not met with the MCAM as proposed because the costs and benefits will be paid by any remaining customers of the LSE in the event of load migration. Departing customers will no longer pay for the resources procured on their behalf, which directly conflicts with the cost causation guiding principle for cost allocation.[15]

This raises a potential concern that if the MCAM as currently proposed is precedential, in future procurements LSEs may have an incentive to defer procurement to (or allow backstopping by) the IOU. This is because if the Commission directed costs and benefits to move with the customer, the LSE would stay insulated from load migration. The option to bill the LSE and allocate the resource to that LSE is a superior option in that it provides the LSE with a mechanism to address load migration by selling their allocation in the market while avoiding the insulation of customers to load migration. The following diagram depicts how the three options address either costs following customers or the ability of the LSE to transact to address load migration:

In the Event of Load Migration			
	MCAM	CAM	Bill LSE
Does RA Attribute and Cost Match Load?	No	Yes	No
Can the LSE Trade the Attribute?	No	No	Yes

[14] Proposed Decision at 49.
[15] *Id.* at 7.

Billing LSEs directly for the procurement costs would avoid the migration problem created by the PD and the resultant unfair imposition of additional costs on remaining customers. LSEs can manage their portfolio and costs based on their load, and adjust their portfolio, if necessary, upon customer migration.

D. The Proposed Decision's Reliance on Public Utilities Code Sections 365.1(c)(2) and 454.51(c) in Requiring Billing of MCAM Through a Non-Bypassable Charge on Customers Rests on Legal Error

The PD recognizes the advantages from a policy perspective of direct billing of LSEs for opt-out and direct procurement.[16] However, the PD cites Public Utilities Code sections 365.1(c)(2) and 454.51(c) as requiring direct cost allocation on a fully non-bypassable basis to "customers" and thereby precluding direct LSE billing. As set forth below, however, sections 365.1(c)(2) and 454.51(c) do not require customer billing in the unique event that the IOU procures system reliability resources on behalf of only some (but not all) LSEs, and thus the PD's insistence that the Commission is required to adopt the customer billing option rests on legal error.

1. Neither Public Utilities Code Section 365.1(c)(2) nor Section 454.51(c) Precludes Direct Billing of LSEs for MCAM Costs

Section 365.1(c)(2) requires the Commission to ensure that in the event it orders an IOU "to obtain generation resources that the commission determines are needed to meet system or local area reliability needs <u>for the benefit of all customers</u> in the electrical corporation's distribution service territory, the net capacity of those generation resources are allocated on a fully non-bypassable basis" to bundled service customers, ESP customers, and CCA customers.[17] The Commission's obligation set forth in section 365.1(c)(2)(A) therefore applies in situations in

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[16] Proposed Decision at 17.
[17] Cal. Pub. Util. Code § 365.1(c)(2)(A) (emphasis added).

which the system (and all customers) will benefit from the procurement, and not the situation in which the IOU is procuring on behalf of only some, but not all LSEs. The unique situation presented by the opt-out and backstop procurement, in which the IOUs procures on behalf a subset of (and therefore not all) LSEs, is therefore not governed by section 365.1(c)(2)(A).

Similarly, section 454.51(c) does not preclude direct LSE billing in the opt-out and backstop procurement situation. Section 454.51(c) requires the Commission to "[e]nsure that the net costs of any incremental renewable energy integration resources procured by [an IOU] to satisfy the need [of ensuring a reliable electricity supply providing optimal integration of renewable energy in a cost-effective manner] are allocated on a fully non-bypassable basis consistent with the treatment of costs identified in [section 365.1(c)(2)(A)]."[18] While the procurement prescribed D.19-11-016 and D.21-06-035 includes renewable resources, the purpose of the procurement orders is to satisfy system reliability requirements rather than promoting the integration of renewable energy resources. Therefore, section 454.51(c) also does not require the Commission to adopt the non-bypassable customer charge in the MCAM situation.

For the reasons set forth above, the Commission's reliance on sections 365.1(c)(2)(A) and 454.51(c) as requiring it to structure the MCAM as a non-bypassable customer charge rather than direct LSE billing is misplaced and rests on legal error.

2. Directly Billing LSEs for Above-Market Procurement Costs for Opt-Out and Backstop LSE Procurement Will Not Increase Costs for Bundled Service Customers

The PD insists that sections 365.1(c)(2)(A) and 454.51(c) require the Commission to structure the MCAM to allocate costs to customers on a "non-bypassable basis." As set forth

[18] Cal. Pub. Util. Code § 454.51(c) (emphasis added).

above, however, sections 365.1(c)(2)(A) and 454.41(c) do not govern the procurement covered by the MCAM. In addition, the PD fails to describe how direct billing of LSEs, rather than a non-bypassable charge, could prevent bundled customer indifference and result in cost shifting. Direct billing of LSEs would ensure that all costs incurred by the IOUs would be collected from the opt-out and backstop LSEs. Those LSEs would then incorporate the costs into their generation rates, just as the IOUs and self-procuring LSEs will do. Even the PD acknowledges that "[a]rguably, allocating the costs directly to the LSE could be characterized as allocating costs on a non-bypassable basis to the LSE on behalf of its customers."[19] Non-IOU LSE customers will not be able to bypass the costs, as the LSEs must recover those costs through their rates. Bundled customers will remain indifferent, as all costs incurred by the IOU will be billed to the opt-out and backstop LSEs. In fact, and as set forth above, allowing IOUs and all LSEs to equally incorporate the costs of the procurement into their generation rates prevents billing distortions and places all LSEs, including IOUs, on a level playing field.

III. IF THE COMMISSION ADOPTS THE MCAM NON-BYPASSABLE CUSTOMER CHARGE, THE PD SHOULD FIX THE BILL DISTORTION, HOLD MIGRATING CUSTOMERS RESPONSIBLE FOR COSTS, AND CLARIFY HOW MCAM CAN BE USED AS PRECEDENT

If, despite CalCCA's strong opposition, the Commission adopts the PD's MCAM non-bypassable customer charge, the Commission should: (1) "fix" the bill distortion by placing above-market MCAM costs on the generation portion of the bill, along with the MPB portion of the costs, (2) require IOUs to track customer migration; and (3) clarify the limited use of the MCAM as precedent.

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19 Proposed Decision at 18.

A. The Commission Should Require the IOUs to Include all MCAM Costs in the Generation Portion of the Bill

If the MCAM is adopted, the Commission should "fix" the resulting bill distortion described above by placing above-market MCAM costs on the generation portion of the bill, along with the MPB portion of the costs. With all generation related costs in the generation component, customers would then be able to fairly compare generation rates of the IOUs, the opt-out/backstop LSEs, <u>and</u> the self-procuring LSEs.

B. The Commission Should Require the Tagging and Tracking of Migrating Customers

Furthermore, in order to address the violation of customer indifference for MCAM charges caused by load migration, the Commission should require IOUs to track and tag customers, as suggested by Southern California Edison Company.[20] This would allow migrating customers to be held accountable for costs incurred on their behalf even if they switch generation providers. One of the reasons for CalCCA's opposition to the proposed MCAM is that it would require extensive rate design and billing system changes. If the Commission rejects CalCCA's recommendation to bill LSEs directly and adopts the MCAM, tracking of customers will be necessary for meeting the cost causation principle.

C. The Commission Should Clarify the Rules for the Limited Use of the MCAM as Precedent

The PD declares its adopted methodology for MCAM treatment as precedent. It states:

> The MCAM adopted herein sets precedent for any future backstop procurement authorized in the [IRP] process in the future, unless and until the Commission adopts a more comprehensive programmatic approach to IRP procurement authorizations.[21]

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20 Proposed Decision at 20-21.
21 *Id.* at 3.

If the Commission adopts the MCAM non-bypassable customer charge, the Commission should clarify the rules for limited application to situations in which IOUs, other LSE types, or other entities are required to procure on behalf of some, but not all, LSEs. In the case of a central procurement entity, for example, in which procurement occurs on behalf of all LSEs, the MCAM cost allocation mechanism would be inapplicable.

IV. 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,
General Counsel and Director of Policy
CALIFORNIA COMMUNITY CHOICE ASSOCIATION

April 18, 2022

ATTACHMENT A
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS
ON THE PROPOSED DECISION ON MODIFIED COST ALLOCATION MECHANISM
FOR OPT-OUT AND BACKSTOP PROCUREMENT OBLIGATIONS

PROPOSED CHANGES TO FINDINGS OF FACT,
CONCLUSIONS OF LAW AND ORDERING PARAGRAPHS

FINDINGS OF FACT

~~12. Public Utilities Code Sections 454.51(c) and 365.1(c)(2), taken together, require that the above-market costs of any IOU opt-out or backstop procurement required by D.19-11-016, or backstop procurement required by D.21-06-035, be allocated on a non-bypassable basis to the relevant benefitting customers.~~

13. ~~To meet statutory requirements against cost shifting, a non-bypassable customer charge~~ <u>Direct billing of responsible LSEs</u> is required as a billing mechanism for recovering the above-market procurement costs incurred by the IOUs on behalf of other LSEs pursuant to D.19-11-016 and D.21-06-035.

34~~.~~ ~~The remaining costs shall be recovered from current Opt-Out or Deficient LSE customers via a non-bypassable ch~~

CONCLUSIONS OF LAW

2. ~~Under statutory requirements in Section 454.51(c) and 365.1(c)(2),~~ the above-market costs of any IOU backstop procurement required by D.19-11-016 must be recovered by ~~imposing non-bypassable customer charges billed to benefitting retail customers~~ <u>directly billing the responsible LSEs for such costs.</u>

~~9. The MCAM adopted in this order meets statutory requirements by allocating above-market costs to bundled service customers, Opt-Out LSE customers, and Deficient LSE customers on a non-bypassable basis and market costs to Opt-Out or Deficient LSEs.~~

~~10. It is not necessary to track and tag every customer of a non-IOU LSe in order to achieve the principles of bundled customer indifference and compliance with statutory requirements under the MCAM structure adopted herein.~~

~~11. MCAM charges should be required to appear as a separate billing line item for non-IOU LSE customers, so that customers can more effectively compare costs related to the provision of generation and distribution services.~~

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

REPLY COMMENTS OF SILICON VALLEY CLEAN ENERGY AUTHORITY, PENINSULA CLEAN ENERGY AUTHORITY, MARIN CLEAN ENERGY, SAN JOSE CLEAN ENERGY AUTHORITY, AND SONOMA CLEAN POWER AUTHORITY ON THE 2021 DISTRIBUTION INVESTMENT DEFERRAL PROCESS

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April 18, 2022

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

REPLY COMMENTS OF SILICON VALLEY CLEAN ENERGY AUTHORITY, PENINSULA CLEAN ENERGY AUTHORITY, MARIN CLEAN ENERGY, SAN JOSE CLEAN ENERGY AUTHORITY, AND SONOMA CLEAN POWER AUTHORITY ON THE 2021 DISTRIBUTION INVESTMENT DEFERRAL PROCESS

Pursuant to the June 21, 2021 Administrative Law Judge's Ruling Modifying the Distribution Investment Deferral Framework ("DIDF") Process and Attachment B of Resolution E-5190, issued January 22, 2022, presenting the Standard Offer Contract and Partnership Pilot Evaluation Timeline modifying the Ruling to require comments on the DIDF reforms by April 4, 2022 and reply comments by April 18, 2022, Silicon Valley Clean Energy Authority, Peninsula Clean Energy Authority, Marin Clean Energy, San Jose Clean Energy, and Sonoma Clean Power Authority (collectively, the "Joint CCAs") respectfully submit these reply comments responding to party comments filed on April 4, 2022.[1]

The Joint CCAs offer these comments on DIDF reform to highlight recommendations we believe could lead to an increase in the number of cost-effective non-wires alternatives being deployed.

[1] Opening comments were filed by Southern California Edison Company ("SCE"), San Diego Gas & Electric Company ("SDG&E"), Pacific Gas and Electric Company ("PG&E"), the Public Advocates Office ("PAO"), and the California Energy Storage Alliance ("CESA").

I. STANDARDIZATION BETWEEN THE IOUS FOR INCORPORATION OF KNOWN LOAD GROWTH IS IMPORTANT AND SHOULD BE REQUIRED

As discussed in the 2022 Independent Professional Engineer Post DPAG Report ("2022 Report"), each of the IOUs is using different methodologies to incorporate known load growth into their distribution circuit load forecasts.[2] The Joint CCAs support standardization and agree with the Independent Professional Engineer ("IPE") that standardization between the IOUs is a topic worthy of further discussion. The Joint CCAs are concerned that the differing methodologies between the IOUs is leading to "lost opportunities" for candidate deferral opportunities ("CDOs") and believe that standardizing the methodology will ease review and, thereby, help ensure the maximum opportunities are presented for consideration of cost-effective non-wires alternatives. Our concern is heightened by the fact that it appears there may be systemic discounting of projects under current DIDF evaluation processes as discussed below.

The Joint CCAs also regularly receive complaints from their local government members that PG&E's upgrades to the distribution system to accommodate electrification are slow, cumbersome, and done on timelines that undermine efforts to electrify new and existing development. The consistency of these complaints raises concerns that PG&E continues to underinvest in resources necessary to support upgrades to the distribution system to support community electrification efforts. While the CCAs intend to explore this issue in the community engagement needs assessment portion of the docket, we are concerned that under-forecasting load growth projects in the 3- to 5-year range could limit the amount of potential deferral opportunities, and potentially leading to lower than optimal personnel and resources engaged in upgrades while also leaving cost-effective non-wires solutions off the table. If coupled with the development of known load growth databases, standardized methodologies – including any discounting – would

[2] 2022 Report, pgs. 26-34.

facilitate review of forecasts' accuracy and be a foundation for future efforts to ensure know load growth is accurately reflected in IOU distribution planning.

II. IMPROVEMENTS TO THE PRIORITIZATION PROCESS FOR CANDIDATE DEFERRALS ARE NECESSARY

The concerns expressed above are highlighted by the Public Advocates Office's comments regarding the use of flagging during IOU review of candidate deferral opportunities. In those comments, PAO expresses support for standardization of forecast certainty metrics used by the IOUs, argues for prioritizing the cost-effectiveness metric, and argues for developing absolute thresholds to help eliminate risk that deferrable projects are being excluded from Tier 1 based on arbitrary utility actions.[3] The Joint CCAs fully support these ideas as the changes will support ensuring all means to control runaway distribution system costs – including cost effective non-wires alternatives – are being undertaken.

The Joint CCAs were particularly concerned with the 2022 Report's discussion of how the questions PG&E utilizes in its forecasting certainty questionnaire do not assess the likelihood of forecasting load materializing, but instead focus on other issues. PG&E also appears to be an outlier in how it uses data on new load materializing to discount CDOs while the other two IOUs use this data in the exact opposite manner. As PAO notes, "[s]hould new load materialize, any DER solution that has been contracted would still be expected to be needed."[4]

SCE's flagging of the Alberhill System Project CDO is another example of an IOU decision that seems to require greater review.[5] While this project is coming before the Commission as part of Application 09-09-022, one is left to wonder if a cost-effective alternative could have been identified in the DIDF process obviating the need for an Application process. SCE's comments on

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[3] See PAO comments, pg. 11.
[4] See PAO comments, pg. 8.
[5] See PAO comments, pg. 11; 2022 Report, pg. 59.

the use of DIDF versus an application for a Certificate of Public Convenience and Necessity ("CPCN") only highlight the Joint CCA's concerns that the IOUs are taking actions that result in viable CDOs not being implemented. While it is true that the CPCN process necessarily requires consideration of alternatives, that process is slow, cumbersome, litigious, and expensive – exactly the situation that the DIDF process is designed to avoid so that cost-effective non-wires alternatives can proceed in a timely fashion to save ratepayers money. For these reasons, the Joint CCAs support PAO's request that all Tier 1 projects downgraded to Tier 2 or Tier 3 by the IOUs be reviewed by the IPE to prevent under-valuation and exclusion from further consideration CDOs for reasons other than deferral viability.

PG&E's discussion of how cost allocation could be undermining its ability to contract with selected resources for services beyond distribution deferral lacks merit. PG&E's comments do not clearly explain why the current cost allocation process undermines IOU ownership bids, nor do the comments address how its proposal would be consistent with Commission decisions, such as D.18-02-004, carefully allocating costs to bundled and unbundled customers based on the services they receive from a particular resource. PG&E also does not clearly explain how procuring additional value streams beyond distribution deferral – such as ancillary services or resource adequacy – for their customers from a successful deferral project creates fairness and equity concerns. PG&E appears to be arguing that because a deferral project has a primary purpose in deferring distribution upgrades then all other value streams for services provided to bundled customers must be spread to bundled and unbundled customers. This outcome is simply at odds with state law requiring unbundled customers to only pay for benefits they receive from the IOU.[6] If a project can offer additional services, PG&E has an open need for those services, and the price of those services is cost-effective compared to other options, minimizing costs to PG&E's customers strongly supports

[6] See Public Utilities Code, Sec. 366.2(k)(1).

PG&E's procurement of those services. If that happens, their bundled customers should pay for the services PG&E procures on their behalf and nobody else. This outcome does not create any fairness or equity concerns. There may be merit in reforming DIDF processes to create an open season for selected projects to offer non-deferral services to other load serving entities ("LSEs") so that those LSEs have an opportunity to procure non-deferral services from that project. Such a change would ensure the full value of these projects can receive compensation.

III. CONCLUSION

The Joint CCAs appreciate the opportunity to offer these reply comments on DIDF reform recommendations.

DATED: April 18, 2022

Respectfully submitted,

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**STATE OF CALIFORNIA ENERGY RESOURCES
CONSERVATION AND DEVELOPMENT COMMISSION**

In the Matter of: 2022 Load Management Rulemaking	Docket No. 21-OIR-03

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS
ON THE PROPOSED REVISIONS TO THE LOAD MANAGEMENT STANDARDS**

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April 20, 2022

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STATE OF CALIFORNIA ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION

In the Matter of: 2022 Load Management Rulemaking	Docket No. 21-OIR-03

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED REVISIONS TO THE LOAD MANAGEMENT STANDARDS

The California Community Choice Association[1] (CalCCA) submits these Comments pursuant to the *Corrected Notice of 15-Day Public Comment Period*, dated April 5, 2022, on the *Proposed Revisions to the Load Management Standards* (the "15-Day Proposed Amendments").

I. INTRODUCTION

CalCCA supports the California Energy Commission's (Commission's) efforts to establish broad load management standards (LMS) that incentivize third-party automation providers to create products to automate demand flexibility. Community choice aggregators (CCAs) are eager to provide load-management tools for their customers and welcome the opportunity to work with the Commission to advance these goals. However, the Commission must only proceed in accordance with its jurisdictional authority, and not overreach to ensure success of its program. The inclusion of CCAs in the proposed LMS oversteps the authority

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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.

granted to the Commission in Public Resources Code (PRC) section 25403.5 and is legally unsustainable.

In addition to the legal prohibition, CalCCA has identified several program "flaws" in the proposed regulations that would create barriers to even voluntary CCA participation. One such flaw, the inclusion of CCAs in the definition of "Utility," was adequately addressed by the Commission in the 15-Day Proposed Amendments. However, several other flaws remain in the proposed language, including that:

- CCAs cannot implement an hourly locational marginal cost-based rate until the investor-owned utilities (IOU) develop the data and billing systems to incorporate such a rate;
- The Commission's finding that CCA costs to implement the LMS are negligible is unsubstantiated; and
- The Commission has arbitrarily excluded electric service providers (ESPs) and small publicly-owned utilities (POUs) among the entities subject to the LMS and must modify the proposal to apply the standards consistently.

II. THE COMMISSION DOES NOT HAVE JURISDICTION TO MANDATE CCA COMPLIANCE WITH ITS LOAD MANAGEMENT STANDARDS

The 15-Day Proposed Amendments does not address CalCCA's continuing assertion, in both written comments and in conversations with Commission staff, that the Commission does not have jurisdictional authority to mandate CCA compliance with the LMS.[2] The LMS are established pursuant to PRC section 25403.5, which provides jurisdiction to the Commission to "adopt standards by regulation for a program of electrical load management for each utility service area."[3] Included within the "techniques" for load management are "[a]djustments in rate

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[2] *See*, *Comments of the California Community Choice Association to the California Energy Commission on the Draft Staff Report*, Docket Log (DL) 19-OIR-01 (June 4, 2021) (CalCCA June 4, 2021 Comments); *California Community Choice Association's Comments on the Proposed Amendments to the Load Management Standards Contained in the California Code of Regulations, Title 20*, DL 21-OIR-03 (Feb. 7, 2022) (CalCCA Feb. 7, 2022 Comments).

[3] Cal. Pub. Res. Code § 25403.5.

structure to encourage use of electrical energy at off-peak hours or to encourage control of daily electrical load."[4] A "service area" is defined in the PRC as "any contiguous geographic area serviced by the same electric utility."[5] As recognized by the Commission's 15-Day Proposed Amendments removing CCAs from the definition of "Utility," CCAs are not "electric utilities." Instead, the Commission contends that because CCAs operate within the geographical service territories of electric utilities, the LMS apply to CCAs that provide electricity to customers within these service territories.[6]

As CalCCA has explained in detail, the proposed LMS overstep the Commission's jurisdictional boundaries.[7] Specifically:

- PRC section 25403.5 has never been amended to expressly apply to or include CCAs within the LMS, despite the legislature imposing obligations on CCAs in other PRC sections; [8]

- The Amendments unlawfully sweep CCAs into the load management standards generally, and step squarely into the ratemaking arena, requiring CCAs to implement a very specific rate methodology;[9]

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4 *Id.,* § 25403.5(a)(1).

5 *Id.,* § 25118.

6 Final Staff Report at 17.

7 *See* CalCCA June 4, 2021 Comments; CalCCA Feb. 7, 2022 Comments.

8 PRC section 25403.5 was originally enacted to require a utility to certify that it was in compliance with the LMS before the Commission would approve sites for a new power plant to effectively coordinate new capacity with load needs. Cal. Pub. Res. Code § 25403.5(e) (1976) (amended in 1980 through AB 3062 (stats. 1980) to eliminate a penalty clause, and to add a forecast reporting requirement for electric utilities). Senate Bill (SB) 1389 (stats. 2002) shifted forecast reporting requirements to the Integrated Energy Policy Report (IEPR). Notably, the direction for electric utilities to report on load management standards was eliminated, but PRC section 25302.5(a) did allow the Commission to require in the IEPR "submission of demand forecasts, resource plans, market assessments, and related outlooks from electric . . . utilities, . . . and other market participants," including CCAs. Therefore, the IEPR process established in 2002 expressly includes CCAs, but the load management standards (adopted before the creation of CCAs) were never amended to include CCAs.

9 *See* Proposed LMS Regulations, § 1623(a) (requiring utilities and CCAs to develop "marginal cost-based rates," calculated as "the sum of the marginal energy cost, the marginal capacity cost (generation, transmission, and distribution), and any other appropriate time and location dependent marginal costs, including social costs, on a time interval of no more than one hour. Energy cost computations shall reflect locational marginal pricing as determined by the associated balancing

- The Commission’s mandate of a specific rate methodology in the LMS infringes on CCA governing boards’ exclusive ratemaking approval authority established in 2002 by Assembly Bill (AB) 117;[10]

- The Final Staff Report acknowledges that the Commission does not have rate approval authority over CCAs;[11] and

- The LMS unlawfully provides the Commission, and not CCA governing boards, the right to impose injunctive relief or impose penalties on CCAs that do not comply with the LMS.[12]

CCAs share the goals of facilitating load management activities by consumers that reduce peak electricity demand, helping to balance electricity supply and demand to support grid reliability and providing clean and affordable electricity services to Californians. However, the Commission does not have the authority to mandate CCA compliance with the LMS. To resolve the Commission’s jurisdictional overreach, including the unlawful infringement on CCA rate autonomy and operations, the Commission should revise the 15-Day Proposed Amendments to apply the LMS regulations, including the marginal cost rate requirements, to CCAs on a *voluntary basis.*

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authority, such as the California Independent System Operator, the Balancing Authority of Northern California, or other balancing authority. Marginal cost computations shall reflect variations in the probability and value of system reliability of each component (generation, transmission, and distribution). Social cost computations shall reflect, at a minimum, the locational marginal cost of associated greenhouse gas emissions.”).

10 AB 117, Stats. 2002; ch. 838 (codified at Cal. Pub. Util. Code § 366.2(c)(3)).

11 Final Staff Report at 17 (“[s]pecific to rate structure, the CEC does not have exclusive or independent authority. For example, rates proposed in compliance with the load management standards are subject to approval by . . . CCA governing boards . . . .”).

12 *See* Proposed LMS Regulations, § 1623(a) (“[t]his standard requires that each . . . CCA develop marginal cost-based rates structured according to the requirements of this article and that the . . . CCA submit such rates to its rate-approving body for approval”); § 1621(f) (“[t]he Executive Director may, after reviewing the matter with the . . . CCA, file a complaint with the Commission . . . or seek injunctive relief if a . . . CCA: (1) fails to adhere to its approved load management standard plan, . . . or (5) violates the provisions of this article.”).

III. OTHER FLAWS IN THE LMS CREATE BARRIERS TO EVEN VOLUNTARY CCA PARTICIPATION

A. The 15-Day Proposed Amendments Adequately Address CalCCA's Request to Remove CCAs From the Definition of "Utility" and Limit LMS Application to Sections 1621 and 1623

The 15-Day Proposed Amendments remedy one "flaw" CalCCA has identified in comments by removing CCAs from the definition of "Utility."[13] The regulations as originally proposed would have effectively incorporated CCAs into all existing load management standards including sections 1622 (residential electric water heaters and air conditioners), 1624 (swimming pool filter pumps, and 1625 (non-residential load management standard). In addition, the expanded definition of "Utility" to include CCAs would have set a precedent for any future regulations promulgated under the CEC's load management authority. The 15-Day Proposed Amendments remedy these concerns by: (1) modifying section 1621(b) to explicitly state that CCAs are not subject subsections 1622, 1624, and 1625 of Article 5; and (2) removing CCAs from the definition of "Utility" in section 1621(c)(17). In addition, the 15-Day Proposed Amendments modify sections 1621 and 1623 to incorporate the changes to the application of the regulations and the definition of "Utility."

In addition, while CalCCA does not agree with section 1621(b)'s statement that the standards are "technologically feasible and cost-effective" (as explained in more detail below), to remain consistent with the other sections removing CCAs from the definition of "Utility," the Commission should change the word "including" in the last sentence of the section to "and":

> The Commission has found these standards to be technologically feasible and cost-effective when compared with the costs for new electrical capacity for the above-named electric utilities, ~~including~~and CCAs operating within the service areas of such electric utilities.

13 *See* CalCCA June 4, 2021 Comments at 2-3; CalCCA Feb. 7, 2022 Comments at 10-11.

With this minor change, the 15-Day Proposed Amendments resolve CalCCA's objection to including CCAs in the definition of "Utility."

B. CCAs Cannot Implement an Hourly Locational Marginal Cost-Based Rate Until the IOUs Develop the Data and Billing Systems to Incorporate That Rate

Despite the 15-Day Proposed Amendments' fix of the definitional issues, they overlook an issue of timing. The LMS requires marginal cost-based rates for all rate elements – transmission, distribution, and generation. For CCA customers, their bills will combine the IOU's marginal cost rate for distribution and transmission with the CCA's marginal cost rate for generation. Requiring CCAs and IOUs to develop rates contemporaneously for all three elements risks a disconnection between the marginal rates for different rate elements. Asking CCAs to develop and implement rates only once the IOUs have approved transmission and distribution components would enable load-serving entities (LSE) to align the approach for all three elements.

A sequential development of rates – transmission/distribution followed by generation – also addresses another problem. Currently, the data received from the IOUs contains significant gaps that do not allow for the receipt of real-time access to interval data to view CCA load. In addition, because IOUs bill the customers after receiving the generation component from CCAs, the IOUs cannot bill for the rate until they develop the appropriate billing systems. As noted in Southern California Edison Company's (SCE) February 7, 2002 comments, the timeframe for SCE to develop the framework for rolling out real-time pricing for one class of customers to align "with SCE's current IT and billing infrastructure" is eight years.[14] As SCE notes, "[a]ppropriate time is needed to ensure success with executing this framework and the

14 *Southern California Edison's Comments on the California Energy Commission (CEC) Docket No. 21-OIR-03, Southern California Edison (SCE) Written Comments on Proposed Regulatory Language for the Load Management Standards Regulations* (Feb. 7, 2022), at 1-2.

accompanying regulatory decision-making process."[15] CCAs can only implement such a rate after the IOUs complete their IT and billing infrastructure upgrades to handle such a rate. Therefore, from a technical feasibility perspective, implementation by CCAs of the rate prescribed in the LMS regulations is many years off and will depend on the IOU implementation of their rates through upgrades to their data and billing systems.[16]

C. The Finding That CCA Costs to Implement the LMS are Negligible is Unsubstantiated

The Commission's statements regarding the costs associated with incorporating CCAs into the LMS are unsubstantiated. Section 1622(h) of the 15-Day Proposed Amendments states that:

> There shall be no reimbursement to local government entities for the costs of carrying out the programs mandated by these standards, because the Commission has found these standards to be cost-effective. The savings which these entities will realize as a result of carrying out these programs will outweigh the costs associated with implementing these programs.[17]

The CEC's assumption that the rates developed pursuant to the LMS will be "cost-effective" for CCAs is not supported by the record. In fact, the Final Staff Report includes the fiscal impact for Publicly-Owned Utilities (POUs) as local governmental entities, but not CCAs.[18] Given the complexity and data-driven nature of the rate prescribed in the LMS, however, there will be significant costs associated with developing a proposal to present to a CCA board. Once presented, the Board may not adopt the proposal. In such a case, there is no way to recover the

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15 *Id.* at 2.

16 In addition, in the event CCAs can voluntarily comply with the LMS, the Commission should ensure that the rate structure, including the definition of marginal cost-based rates, is not overly prescriptive in nature and allows for innovation in rate design. CCAs and other LSEs should maintain flexibility to create innovative and cost-effective rates that reflect their specific marginal costs and customer needs.

17 15-Day Proposed Amendments § 1622(h).

18 Final Staff Report at 77-78 (Tables 15-16).

costs for developing the proposal. The CEC's fiscal impact analysis also failed to account for the significant implementation costs associated with billing system upgrades. These costs would be especially more burdensome for smaller CCAs, whose load shares are more comparable to smaller POUs. The Commission has therefore not properly evaluated the cost-effectiveness of developing these rates for CCAs.

As the Commission has not adequately substantiated its claims that the implementation of the LMS would be cost effective for CCAs, the Commission should also clarify that section 1622(h) of the proposed LMS does not expressly preclude CCAs from seeking cost recovery from all ratepayers for implementation of the LMS with the California Public Utilities Commission. As CCAs would be developing their own marginal cost-based generation rates, there would necessarily be costs to develop the rates and infrastructure necessary to implement and bill for such rates. If the IOUs and CCAs are both developing these systems, attention must be paid to the cost recovery mechanisms of both the IOUs *and* CCAs to ensure that customers are not paying twice for the implementation of the LMS. Any determination of the reasonableness of cost recovery mechanisms must not be prejudiced by the language adopted in the LMS.

In addition, the Final Staff Report states that:

> [t]he CEC assumes that CCAs in IOU service territories will pass through the hourly tariffs that are developed and implemented by the IOU in whose service territory they are located. This implementation strategy is projected to result in no direct costs or benefits for the CCAs but will be most aligned with grid needs. CCAs' customers will benefit from energy costs reduction. CCAs' reporting effort is expected to be negligible as CCAs only need to inform CEC about the hourly tariffs they pass through from their respective IOU.[19]

[19] *Id.* at 78.

CCAs do not “pass through” rates from the IOUs. CCAs have their own generation rates, developed by the CCAs and approved by the CCA governing boards. CCA rates compete with IOU generation rates. CCAs provide their generation rates to the IOUs, who bill CCA customers by adding their transmission and distribution rates. CCA rate design requires significant effort and cost, similar to IOU rate design. Further, the regulations describe rates that are approved by a CCA's governing board. However, CCA governing boards have no authority to approve IOU rates. The CCAs cannot simply rely on IOU rates to comply with the plain language of the regulation.

IV. THE COMMISSION HAS INCLUDED CCAS WHILE ARBITRARILY EXCLUDING ESPS AND SMALL POUS FROM THE LMS

The proposed regulations apply to the IOUs, specific large POUs, and all CCAs.[20] Curiously absent from the list of LSEs required to comply with the LMS are ESPs and small POUs. CalCCA questions why the Commission excluded ESPs when they served ten percent of California‘s load in 2021.[21] Small POUs together also serve a substantial portion of California’s load. The Final Staff Report states that part of the reason it includes CCAs within the reach of its LMS is because “any other interpretation would diminish the effectiveness of the proposed amendments to the [LMS] and defeat the purpose of the statute.”[22] The same can be said of ESPs and small POUs. The proposed regulations’ exclusion of ESPs and small POUs may be interpreted as an arbitrary and capricious omission that should be explained. The Commission must apply the LMS even-handedly among all LSEs operating in the same service area to ensure consistency and competitiveness.

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20 Proposed Amendments § 1621(b).
21 *California Energy Demand 2021-2035 Baseline Forecast - Mid Demand Case*, January 2022.
22 Final Staff Report at 17.

V. CONCLUSION

CalCCA looks forward to further collaboration on this topic.

Respectfully submitted,

Evelyn Kahl

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CALIFORNIA COMMUNITY CHOICE
ASSOCIATION

April 20, 2022

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Approval of 2024-2031 Energy Efficiency Business Plan and 2024-2027 Portfolio Plan. (U 39 M)	Application 22-02-005 (Filed February 15, 2022)
And Related Matters.	Application 22-03-003 Application 22-03-004 Application 22-03-005 Application 22-03-007 Application 22-03-008 Application 22-03-011 Application 22-03-012 (Consolidated)

REPLY TO RESPONSES AND PROTESTS TO THE APPLICATION OF MARIN CLEAN ENERGY FOR APPROVAL OF 2024-2031 ENERGY EFFICIENCY BUSINESS PLAN AND 2024-2037 ENERGY EFFICIENCY PORTFOLIO PLAN

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Approval of 2024-2031 Energy Efficiency Business Plan and 2024-2027 Portfolio Plan. (U 39 M)	Application 22-02-005 (Filed February 15, 2022)
And Related Matters.	Application 22-03-003 Application 22-03-004 Application 22-03-005 Application 22-03-007 Application 22-03-008 Application 22-03-011 Application 22-03-012 (Consolidated)

REPLY TO RESPONSES AND PROTESTS TO THE APPLICATION OF MARIN CLEAN ENERGY FOR APPROVAL OF 2024-2031 ENERGY EFFICIENCY BUSINESS PLAN AND 2024-2037 ENERGY EFFICIENCY PORTFOLIO PLAN

1. Introduction

Pursuant to Rule 2.6(e) of the California Public Utilities Commission ("Commission," or "CPUC") Rules of Practice and Procedure, Marin Clean Energy ("MCE") submits the following reply to the responses and protests[1] to the Application of MCE For Approval of 2024-2031 Energy Efficiency Business Plan and 2024-2027 Energy Efficiency Portfolio Plan ("MCE Application") filed March 4, 2022. MCE specifically responds to the responses of Pacific Gas & Electric ("PG&E"),[2] Natural Resources Defense Council ("NRDC"),[3] California Efficiency + Demand

[1] Sierra Club Protest to Program Administrator Business Plan Applications; Protest of the Public Advocates Office of Utility Program Administrator, Regional Energy Network and Regional/Municipal Government Applications for Energy Efficiency 2024-2027 Portfolios and 2024-2031 Business Plans.
[2] PG&E's Response to 2024 Energy Efficiency Business Plan Applications.
[3] NRDC Response to the Program Administrators' Energy Efficiency Applications and Business Plans.

Management Council ("the Council"),[4] Enervee,[5] Recurve Analytics, Inc. ("Recurve"),[6] Redwood Coast Energy Authority ("RCEA or RuralREN"),[7] and Southern California Regional Energy Network ("SoCalREN")[8] filed with the Commission on April 15, 2022.

In this reply, MCE states: (1) its commitment to, and understanding of, the Equity segment in energy efficiency ("EE") portfolio programs; (2) limited data sharing amongst EE program administrators ("PAs") for the purposes of determining EE program eligibility is squarely within the scope of the EE proceeding and prudent; and (3) the Commission may and should explore updating the application of EE cost-effectiveness methods to EE portfolio programs in its review of EE portfolio and business plan applications.

MCE finds EE critical to advancing Equity, energy savings, decarbonization, workforce development, grid reliability and energy affordability for ratepayers. MCE remains committed to balanced, innovative, and efficient programs in concert with all EE PAs to ensure optimal performance of EE programs.

2. Background

On February 15, 2022, PG&E submitted its Application for Approval of its 2024-2031 Energy Efficiency Strategic Business Plan and 2024-2027 Portfolio Plan ("PG&E Application"). MCE, as a Commission recognized "apply to administer" PA of EE programs,[9] respectfully submitted the MCE Application on March 04, 2022, concurrently with other investor-owned utility ("IOU"), and

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[4] Response of the Council to Applications of PG&E, Bay Area Governments, County of Ventura, San Diego Gas and Electric Company, Southern California Edison Company, Southern California Gas Company, Southern California Regional Energy Network and Marin Clean Energy for Approval of their 2024-2031 Energy Efficiency Business plans and 2024-2027 Energy Efficiency Portfolio Plans and Motion of RCEA on Behalf of RuralREN for Approval of Energy Efficiency Portfolio Application.
[5] Response of Enervee to Program Administrators' Business Plan and Energy Efficiency Portfolio Filings.
[6] Comments of Recurve on Business Plan Applications for 2024-2027.
[7] Response of RCEA to Energy Efficiency Applications.
[8] Response of the SoCalREN on Consolidated Energy Efficiency 2024-2031 Business Plan Applications.
[9] D.14-01-033, OP 1 at 50; D.18-05-041, OP 1 at 182; D.21-12-011 at 28-31.

regional energy networks ("RENs") PAs. On March 4, 2022, RCEA, on behalf of RuralREN, filed a Motion for Approval of Energy Efficiency Portfolio Application.

On March 17, 2022, Chief Administrative Law Judge Ann E. Simon issued *Chief Administrative Law Judge's Ruling Consolidating Proceedings; Preliminarily Determining Category, Need for Hearings, and Assignment; and Setting Protest and Response Deadlines* ("Consolidation Ruling"). The Consolidation Ruling consolidated "the applications of the energy efficiency program administrators for their 2024-2027 portfolios and 2024-2031 business plans as required in Decision 21-05-031."[10] The Consolidation Ruling further moved consideration of RCEA's motion into the consolidated application proceeding. Finally, the Consolidation Ruling set April 15, 2022, as the single deadline for parties to file protests and responses to applications and April 25, 2022, as the deadline for potential replies. This reply is timely and appropriately filed.

3. MCE Supports Meaningful Equity Commitments from All Energy Efficiency Program Administrators.

MCE agrees with several parties that EE programs must support and prioritize the equity goals set forth in the equity segment of the EE portfolios.[11] The equity segment supports programs with the "primary purpose" of providing the benefits of EE to customers facing historic access barriers.[12] MCE worked with partners and stakeholders to maximize its Application's advancement of equitable outcomes consistent with Commission guidance.[13] In agreement with the Commission, MCE additionally understands, and strives to support, equitable outcomes in all its programs regardless of their formal designation as an equity program.[14] MCE recognizes the

[10] Consolidation Ruling at 2.
[11] NRDC Response at 2-3; SoCalREN at 6-8.
[12] D. 21-05-031 at 14-15.
[13] MCE Application, Exhibit 2, Chapter 3, Section 4.2 at 3-20-3-30.
[14] *See* Cal. Pub. Util. Comm'n, Environmental and Social Justice Action Plan version 2.0 (April,

Commission's *Environmental and Social Justice Action Plan* ("ESJ Action Plan") goals apply across the EE portfolio segments and in the scope of their consolidated review.[15] MCE appreciates the significant equity proposals of BayREN & 3C-REN, SoCalREN and RuralREN. MCE additionally appreciates the focused reviews of EE proposals working to ensure the fulfillment of the Commission's equity goals and D.21-05-031.[16]

In furtherance of those equity goals and compliance with D.21-05-031, MCE supports all PAs making the maximum equity commitment possible within their portfolios. Many ratepayers across California are currently experiencing dangerously high energy burdens forecasted to continue rising.[17] All ratepayers should benefit from EE programs especially those facing disproportionate financial and environmental burdens from California's energy system.[18] Successful equity programs must meet the specific and diverse needs of their intended beneficiaries. This requires thoughtful program design, implementation and evaluation anchored in those community needs.[19] Equity programs benefit from diverse PAs and implementers working in trusted partnership with

2022), available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/news-and-outreach/documents/news-office/key-issues/esj/esj-action-plan-v2jw.pdf ("ESJ Action Plan") at 8 (stating its goal to incorporate equity to all the agency's programs and services); *See* Marin Clean Energy, About Us, *available at*: https://www.mcecleanenergy.org/about-us/("MCE's mission is to confront the climate crisis by eliminating fossil fuel greenhouse gas emissions, producing renewable energy, and creating equitable community benefits").

[15] ESJ Action Plan at 2 (including, but not limited to: Goal 1: Consistently integrate equity and access considerations throughout CPUC regulatory activities; Goal 2: Increase investment in clean energy resources to benefit ESJ communities, especially to improve local air quality and public health; Goal 7: Promote high road career paths and economic opportunity for residents of ESJ communities; Goal 9: Monitor the CPUC's environmental and social justice efforts to evaluate how they are achieving their objectives.").

[16] NRDC Response at 12-18; RCEA Response 2-3; SoCalREN Response at 6-8.

[17] Cal. Pub. Util. Comm'n, Utility Costs and Affordability of the Grid of the Future (May, 2021), available at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/office-of-governmental-affairs-division/reports/2021/senate-bill-695-report-2021-and-en-banc-whitepaper_final_04302021.pdf.

[18] ESJ Action Plan at 21.

[19] California Environmental Justice Alliance, Building a Just Energy Future: A Framework for Community Choice Aggregators to Power Equity and Democracy in California, pp. 6-7 (2020), available at: https://caleja.org/wp-content/uploads/2020/11/CEJA-CCA-REPORT-SINGLE-PAGE.pdf at 6.

the communities they aim to serve. The Commission and all PAs have a shared responsibility to meaningfully invest in equity programs. The Commission should encourage maximum equity commitments for all EE PAs.

4. The Commission Should Require Appropriate Demand Response Participation Data Sharing Between PG&E and MCE.

The Commission should require necessary demand response ("DR") program participation data sharing between PG&E and MCE. PG&E responded to MCE's Application policy recommendation[20] on DR data sharing by stating that, while important, it is out of scope in the EE proceeding.[21] MCE disagrees and finds DR data sharing required for successful administration of EE programs within the scope of the EE proceeding. The Commission wisely integrated demand response activities and programs into its EE portfolio.[22] The Commission appropriately justified this integration by outlining how closer integration of EE and DR will support both the energy savings goals of EE and the grid reliability goals of DR.[23] The Commission previously scoped potential DR rule changes in the EE proceeding.[24]

The Commission additionally stated DR program rule changes and guidance are within the scope of the *Energy Efficiency Rolling Portfolios, Policies, Programs, Evaluation, and Related Issues* proceeding. The *December 23, 2021, Assigned Commissioner and Administrative Law Judge's Ruling* states the Commission anticipates addressing implementation issues related to the

[20] MCE Application at 25-26.
[21] PG&E Response at 4-6.
[22] D.21-12-011 at 5 (requesting EE proposals that integrate DR investments, measures, and peak load reductions).
[23] *See e.g.* D.21-12-011 at 24 (authorizing EE projects that produce "verifiable energy savings at peak times").
[24] *Id*. at 5 ("Removing rules or requirements that may create barriers to expedited or accelerated energy efficiency projects").

summer reliability DR focused EE programs in its review of EE applications.[25] The Commission expressly states that their consideration may go beyond the Summer of 2022 and 2023 reliability programs and include DR issues in the 2024-2027 proposals.[26] Further, the Commission states it may consider related "[reliability] issues that would impact energy efficiency policy beyond the 2024-2027 proposals" in its review of EE applications.[27]

The Commission may explore the issues in this proceeding particularly as it relates to MCE's need to perform eligibility verifications to avoid dual enrollment between MCE's Peak FLEXmarket programs and the demand response programs managed and overseen by PG&E.[28] MCE clarifies its policy recommendation only requests program participation data limited to whether a customer is enrolled in a DR program and the name of the DR program. This information is necessary to determine eligibility for programs within MCE's Application. MCE requests the Commission consider this request separate from other demand response data and customer usage data requests from non-Load Serving Entities.[29] MCE requires PG&E's program DR program participation data to functionally and responsibly administer its EE programs. The Commission should require DR data sharing between MCE & PG&E in this proceeding.

5. The Commission should explore updates to Energy Efficiency Cost-Effectiveness Methods in the Energy Efficiency Proceeding.

MCE requested the Commission continue to evaluate the future use of the Program Administrator Cost Test ("PAC") instead of the Total Resource Cost ("TRC") test to evaluate cost effectiveness under the EE portfolio.[30] PG&E stated in its response, evaluation of the tests'

[25] R.13-11-005, Assigned Commission and Administrative Law Judge's Ruling, (December 23, 2021) at 3.
[26] *Id*. 3-4.
[27] *Id*. at 3-4.
[28] D.21-12-011 at 30-31 (approved in EE proceeding R.13-11-005).
[29] *See e.g.*, PG&E Response at 4-6 (conflating MCE's data request with other distinct data requests).
[30] MCE Application at 26-27.

impacts on the EE portfolio should be discussed exclusively in the Integrated Distributed Energy Resources ("IDER") proceeding.[31] MCE disagrees and requests the Commission continue to evaluate the effectiveness of EE metrics, tests, and tools within the EE proceeding.

The Commission's EE decisions and rulings regularly address the performance and suitability of cost effectiveness metrics, including the PAC and TRC, on EE applications. D.21-05-031 *Assessment of Energy Efficiency Potential and Goals and Modification of Portfolio Approval and Oversight Process*, for example, thoroughly discusses the appropriateness and impacts of using the TRC, PAC and the Avoided Cost Calculator ("ACC") to evaluate EE applications and programs.[32]

The Commission already scoped cost-effectiveness issues into its review of EE applications and required coordination with the IDER proceeding ordering, "[c]oordination with the integrated distributed energy resource rulemaking (R.14-10-003) related to cost-effectiveness and locational targeting of energy efficiency[.]"[33] MCE seeks only a determination that the PAC should be the primary test for EE resources, not a change to any methodology for the PAC or TRC. MCE recognizes the Commission oversees many important and related rulemakings on cost-effectiveness more broadly. However, larger questions on Commission cost-effectiveness methodologies and ACC valuation, as discussed under the IDER proceeding, are separate from determining which cost-effectiveness methods and thresholds are most appropriate to evaluate EE programs specifically.

MCE requests the Commission undertake this specific and narrowly tailored evaluation of the primary cost-effectiveness test for EE programs. MCE believes this cost-effectiveness discussion

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[31] PG&E Response at 6-7.
[32] D.21-05-031 at 20-23, 51-53.
[33] Consolidation Ruling at 5.

will greatly benefit from the record in this proceeding. MCE notes several responding parties offered support for its cost-effectiveness policy recommendation.[34] MCE's request is thus appropriately scoped and ripe for this EE proceeding.

6. Conclusion

MCE thanks Commissioner Shiroma, Administrative Law Judge Fitch and Administrative Law Judge Kao for their thoughtful consideration of this reply to party protests and responses. MCE looks forward to working with the Commission, the PAs, parties, and other stakeholders to adopt and implement successful EE programs.

Respectfully submitted,

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[34] The Council Response at 8-9; NRDC Response at 2, 19; Enervee Response at 7; Recurve Response at 3-5.

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

Order Instituting Rulemaking to Continue Electric Integrated Resource Planning and Related Procurement Processes.	R.20-05-003

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON THE PROPOSED DECISION ON MODIFIED COST ALLOCATION MECHANISM FOR OPT-OUT AND BACKSTOP PROCUREMENT OBLIGATIONS

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April 25, 2022

TABLE OF CONTENTS

SUMMARY OF RECOMMENDATIONS

- ✓ Adopt the recommendations of Alliance for Retail Energy Markets (AReM) and Shell Energy North America (US), L.P. D/B/A Shell Energy Solutions (Shell) to modify the PD to require direct billing of load-serving entities (LSEs) for opt-out and backstop procurement costs;

- ✓ Reject Pacific Gas and Electric Company's (PG&E's) and Southern California Edison Company's (SCE's) request to embed the Modified Cost Allocation Mechanism (MCAM) charge in distribution rates;

- ✓ Reject the request of PG&E, SCE and San Diego Gas & Electric Company (SDG&E) to remove the PD's one-time allocation of Resource Adequacy (RA) capacity and Renewables Portfolio Standard (RPS) attributes to LSEs with load departing after 2019;

- ✓ Adopt the recommendation of Protect Our Communities Foundation (PCF) that if the Commission adopts the investor-owned utility (IOU) customer charge, the costs should move with the customers of the non-IOU LSE to the new provider of service in the event of a non-IOU LSE's bankruptcy or termination of service; and

- ✓ Require the IOUs to seek approval through a Tier 3 Advice Letter for procurement greater than five percent above the opt-out or backstop amount.

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON THE PROPOSED DECISION ON MODIFIED COST ALLOCATION MECHANISM FOR OPT-OUT AND BACKSTOP PROCUREMENT OBLIGATIONS

The California Community Choice Association (CalCCA)[1] submits these reply comments pursuant to Rule 14.3 of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure on the proposed *Decision on Modified Cost Allocation Mechanism for Opt-Out and Backstop Procurement Obligations* (PD or Proposed Decision), issued on March 29 2022.

I. INTRODUCTION

In response to party Opening Comments, CalCCA provides the following recommendations:

- ✓ Adopt the recommendations of AReM/Shell to modify the PD to require direct billing of LSEs for opt-out and backstop procurement costs;
- ✓ Reject PG&E's and SCE's request to embed the MCAM charge in distribution rates;
- ✓ Reject the request of PG&E, SCE and SDG&E's remove the PD's one-time allocation of RA capacity and RPS attributes to LSEs with load departing after 2019;
- ✓ Adopt the recommendation of PCF that if the Commission adopts the IOU customer charge, the costs should move with the customers of the non-IOU LSE to the new provider of service in the event of a non-IOU LSE's bankruptcy or termination of service; and
- ✓ Require the IOUs to seek approval through a Tier 3 Advice Letter for procurement greater than five percent above the opt-out or backstop amount.

II. THE COMMISSION SHOULD ADOPT THE RECOMMENDATIONS OF AREM AND SHELL TO MODIFY THE PD TO REQUIRE DIRECT BILLING OF OPT-OUT AND DEFICIENT LSES

The PD notes the preferred option from a policy perspective of direct billing of opt-out and deficient LSEs as opposed to an IOU customer charge.[2] However, the PD concludes that Public

[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] PD at 17 (having the IOUs bill the appropriate LSEs directly "would be preferable, on a policy basis" and "would be far easier to implement, with no requirement for billing system changes . . . ."); *see also* CalCCA Opening Comments at 3-6 (all references to party Opening Comments are to the comments filed in this Docket in response to the PD on April 18, 2022).

Utilities Code Sections 365.1(c)(2) and 454.41(c) require the Commission to adopt the IOU customer charge rather than directly billing LSEs. In their Opening Comments, AReM and Shell correctly note (as also detailed in CalCCA's Opening Comments) that Sections 365.1(c)(2) and 454.41(c) do not expressly require the Commission to place the MCAM costs in an IOU customer charge.[3] Instead, the Commission can ensure that all benefitting customers pay the costs of the procurement (thereby ensuring a non-bypassable charge) through direct LSE billing. The LSEs paying the MCAM costs will charge customers through their generation rates, just as the IOUs charge their customers for the same costs.

In fact, PG&E/SCE's Opening Comments request significant modifications to the PD to resolve the complexities and significant cost recovery issues associated with an IOU customer charge.[4] In particular, PG&E/SCE note the significant time (up to 24 months) and costs (for PG&E, $3 million) associated with billing system changes to accommodate the MCAM charge.[5] PG&E/SCE note that the Tier 2 advice letter process will introduce additional delay and costs, for which the IOUs request they be able to recover.[6] In addition to the significant rate design issues flagged by PG&E/SCE, these complexities further support the Commission instead adopting direct LSE billing to avoid the significant costs, delay, bill distortion and migration issues presented by the IOU customer charge.

III. THE COMMISSION SHOULD REJECT PG&E/SCE'S REQUEST TO EMBED THE MCAM CHARGE IN THE IOU DISTRIBUTION RATES

If the Commission adopts the IOU customer charge rather than direct LSE billing, it should reject PG&E/SCE's request to embed all MCAM costs in the IOU distribution rates. The PD agrees that:

> embedding the opt-out and backstop procurement costs in the distribution rates [for bundled and opt-out/deficient LSE customers] is not transparent and does not allow for real comparisons between the costs of different providers, causing the potential for unfair competition.[7]

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3 AReM Opening Comments at 3-6; Shell Opening Comments at 3-6.

4 *See* PG&E/SCE Opening Comments at 6-7 (requesting timely cost recovery of additional system upgrades necessary to implement the MCAM customer charge); 8-9 (requesting removal of the MPB costs from the applicable non-IOU LSE portion of a customer's bill); 10 (requesting clarification of the language required in the "Fast Lane" portion of the bill); and 11-12 (requesting clarification on IOU rate design for the MCAM customer charge).

5 *Id.* at 6.

6 *Id.* at 6.

7 PD at 50.

The PD thus attempts to reduce the impact of placing the entire MCAM charge in the distribution portion of the bill by directing the IOUs to place the MPB portion of the costs in the LSEs' generation portion of the bill. The above-market costs would remain in the distribution section of the bill.[8] To increase transparency and promote fair price comparisons for customers, the Commission should direct <u>all</u> opt-out and backstop procurement costs to be included on the generation side of the bill. At a minimum, however, the Commission should reject PG&E/SCE's request to modify the PD to move the MPB portion of the costs out of the generation portion and into the distribution portion of the bill.

Additionally, PG&E/SCE argue that Section 394(f) governing ESPs "prohibits the Commission from regulating generation charges for [ESPs]," and that "[s]imilarly, the Commission does not regulate [CCA] rates."[9] CalCCA agrees with the IOUs' conclusions regarding jurisdiction. Ordering the IOUs to include a separate line item of the MPB costs on the generation portion of the bill, however, does not constitute Commission regulation of ESP or CCA rates. PG&E/SCE's argument should be rejected.

Finally, PG&E/SCE request that the Commission modify the PD's requirement that the MCAM charge be "broken out separately" in a "separate line item" for opt-out and backstop LSE customers, "so that customers can more effectively compare costs that are related to provision of generation and distribution services."[10] PG&E/SCE request that instead of a separate line item, the Commission should include the MCAM charge in the total distribution rate, and communicate to customers elsewhere on the bill the portion of the MCAM charge that is embedded in the distribution rate. With its request to embed both the MPB and above-market costs within the distribution charge, PG&E/SCE would effectively remove all attempts by the Commission in the PD to increase transparency for customers, reduce bill distortions, and ensure fair competition among IOUs/opt-out or deficient non-IOU LSEs and self-procuring LSEs. PG&E/SCE's request should be rejected.

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8 *Id.* at 50.

9 PG&E/SCE Opening Comments at 9.

10 PD at 50.

IV. THE COMMISSION SHOULD REJECT THE IOU'S REQUEST TO REMOVE THE PD'S ONE-TIME ALLOCATION OF RA CAPACITY AND RPS ATTRIBUTES TO LSES WITH LOAD DEPARTING AFTER 2019

The Commission should reject PG&E/SCE's and SDG&E's proposals to eliminate the one-time allocation of RA capacity and RPS energy to the Joint California CCAs.[11] The IOUs argue that the PD violates "settled law" in the Power Charge Indifference Adjustment (PCIA) proceeding (R.17-06-026) by making a "one-time provision" on behalf of customers of the Joint CCAs who departed SDG&E's retail service since 2019. The Joint California CCAs are ordered to pay for the RA capacity and RPS attributes at the MPB (through bilateral contracts), while the departed load customers will pay for the above-market costs through the PCIA.

The Commission should reject the IOUs' conclusion that the PD violates "settled law" concerning allocation of RA capacity and RPS attributes to LSEs who received departing load. First, the Commission is not bound by its past decisions – in fact, its authority to deviate from past decisions is well-established.[12] In addition, the Commission carves out its "one-time provision" for the allocation of the RA capacity and RPS attributes in this unique situation in which SDG&E was aware that a significant portion of its load would depart for the Joint California CCAs after 2019. The Joint California CCAs had filed their Implementation Plans, and the schedule for the load departure was known by SDG&E and the CCAs. SDG&E argues that "load departure is hardly a novel circumstance and cannot justify circumvention of" Commission precedent. However, the Commission's one-time allocation of RA capacity and RPS attributes in this circumstance is justified and ensures that the capacity procured on behalf of the departed load serves the load for which it was specifically intended.

In addition, the PD should be revised to ensure that the non-IOU LSEs can purchase <u>all</u> relevant RA attributes associated with its share of the procurement, including System RA, RPS attributes, <u>as well as</u> any associated Local and Flexible RA attributes. This revision is necessary especially in SDG&E's service territory which does not have a central procurement entity for Local RA.

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[11] PG&E/SCE Opening Comments at 2-4; SDG&E Opening Comments at 3-7. The Joint California CCAs include San Diego Community Power, Clean Energy Alliance, Desert Community Energy, City of Pomona, and Santa Barbara Clean Energy.

[12] D.88-12-083, *In re Pacific Gas & Electric Co.* (1988), 30 Cal.P.U.C.2d 189, 223-225; *see also* D.21-06-042, *Application of Southern California Edison Company (U338E) for Approval of its Charge Ready 2 Infrastructure and Market Education Programs* (June 24, 2021) at 4 ("[i]t is settled that the Commission is not bound by its precedent"); Cal. Pub. Util. Code § 1708 ("[t]he commission may at any time . . . rescind, alter, or amend any order or decision made by it.").

V. THE COMMISSION SHOULD ADOPT PCF'S RECOMMENDATION THAT COSTS MOVE WITH A CUSTOMER IN THE EVENT THE PD ADOPTS IOU CUSTOMER BILLING AND AN LSE FILES FOR BANKRUPTCY OR OTHERWISE TERMINATES SERVICE

PCF argues that if the Commission adopts IOU customer billing for MCAM, in the event of a non-IOU LSE's bankruptcy or termination of service the customer charges (*i.e.*, the MCAM costs) should move with the customers of the non-IOU LSE to the new provider of service to these customers. Direct billing of LSEs will prevent this customer migration issue, and CalCCA requests that the Commission modify the PD to require direct billing of LSEs for the MCAM.[13] If the Commission nonetheless adopts the IOU customer charge for MCAM costs, however, CalCCA agrees with PCF's recommendation. As currently written, the PD would require the MCAM costs in this circumstance to be allocated using the Cost Allocation Mechanism (CAM). However, spreading the costs among all LSEs would constitute an impermissible cost shift.

VI. THE COMMISSION SHOULD REQUIRE THE IOUS TO SEEK APPROVAL THROUGH A TIER 3 ADVICE LETTER FOR PROCUREMENT GREATER THAN FIVE PERCENT ABOVE THE OPT-OUT OR BACKSTOP AMOUNT

PG&E/SCE request modification of the PD to allow the IOUs to seek advice letter approval for opt-out or backstop procurement in excess of the PD's allowance of five percent over the opt-out or deficient quantities.[14] If the Commission modifies the PD to allow the IOUs to seek such approval, the PD should require such request to be through a Tier 3 Advice Letter.

VII. CONCLUSION

CalCCA appreciates the opportunity to submit these reply comments and requests adoption of the recommendations proposed herein.

Respectfully submitted,

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

April 25, 2022

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13 As set forth in CalCCAs' Opening Comments, directly billing LSEs avoids potential cost shifts associated with direct customer billing and customer migration to another LSE. *See* CalCCA Opening Comments at 6-8.

14 PG&E/SCE Opening Comments at 13.

April 25, 2022

VIA ELECTRONIC MAIL

Mr. Pete Skala
Interim Director, Energy and Climate Policy
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

Re: California Community Choice Association's Protest of Pacific Gas and Electric Company's Tier 2 Advice Letter 6551-E Requesting Approval of Market Offer Contract for Power Charge Indifference Adjustment Eligible Renewables Portfolio Standard Resources

Dear Mr. Skala,

Pursuant to the California Public Utilities Commission's (Commission's) General Order (GO) 96-B,[1] the California Community Choice Association[2] (CalCCA) submits this Protest of Pacific Gas and Electric Company's (PG&E's) Tier 2 Advice Letter 6551-E Requesting Approval of Market Offer Contract for Power Charge Indifference Adjustment (PCIA) Eligible Renewables Portfolio Standard (RPS) Resources (Advice Letter), dated April 4, 2022.

I. SUMMARY

- The Commission should not approve the market offer pro forma contract (Market Offer Contract) unless it is revised as follows:
  - Bidders must be allowed to bid on bundled resource pools independent of any bid on unbundled resource pools, as is allowed under Southern California Edison's (SCE's) and San Diego Gas & Electric Company's (SDG&E's) market offer pro forma contracts; and
  - Counterparties to the Market Offer Contract should be provided timely access to meter data, which is necessary for operational and planning purposes.

1 References to "General Rules" are to the general rules identified in General Order 96-B.

2 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.

- CalCCA reserves the right to comment on the terms of the Market Offer Contract following the filing of the investor-owned utilities' (IOUs') "Market Offer Process" and sales strategy documents in May.

II. BACKGROUND

PG&E filed the Advice Letter on April 4, 2022, seeking approval of the Market Offer Contract. The market offer follows the voluntary allocation as part of the Voluntary Allocation and Market Offer (VAMO) process, as directed by Decision (D.) 21-05-030 in the PCIA proceeding (Phase 2 Decision). Under VAMO, PCIA-eligible RPS resources remaining in the IOUs' portfolios following the voluntary allocation elections will be offered for sale to the market. The Phase 2 Decision requires details of the VAMO process to be worked out in the RPS Proceeding. The Advice Letter, including an opportunity for LSEs to raise concerns on the pro forma contracts, is submitted pursuant to D.22-01-004 in the RPS Proceeding.[3]

On February 28, 2022, PG&E filed its Tier 2 Advice Letter 6517-E requesting approval of the pro forma contract to be used in the voluntary allocation phase of VAMO. CalCCA submitted its protest to this Advice Letter on March 21, 2022. Subsequently, PG&E 6517-E, along with the Advice Letters of SCE and SDG&E, regarding their pro forma voluntary allocation contracts, was suspended by the Energy Division for a period of up to 120 days beginning March 29, 2022.[4]

By Ruling dated April 11, 2022, the Assigned Commissioner and Assigned Administrative Law Judge in the RPS Proceeding established a revised schedule for the market offer portion of VAMO.[5] This Ruling requires the IOUs to submit a "Market Offer Process" for Commission and stakeholder review by May 2, 2022, followed by a period for comments and reply comments.[6] The Commission's decision on the Market Offer Process is set for the third quarter of 2022.[7]

By Ruling dated April 21, 2022, the Administrative Law Judge modified this schedule to permit each IOU to separately develop and submit confidential market sensitive "Market Offer Sales Strategies" on May 16, 2022, following the submission of the joint Market Offer Process.[8] The comment and reply comment period on the Market Offer Process will now end in June.

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[3] D.22-01-004, *Decision on 2021 Renewables Portfolio Standard Procurement Plans*, R.18-07-003 (Jan. 13, 2022) (RPS Decision), at 14.

[4] Energy Division Advice Letter Suspension Notice emailed March 29, 2022.

[5] *Assigned Commission and Assigned Administrative Law Judge's Ruling Identifying Issues and Schedule of Review for 2022 Renewables Portfolio Standard Procurement Plans and Denying Joint IOUs' Motion to File Advice Letters for Market Offer Process*, R.18-07-003 (Apr. 11, 2022).

[6] *Id.,* Attachment A.

[7] *Id*.

[8] *Administrative Law Judge's Ruling Modifying the Schedule for Track 1 of the 2022 Renewables Portfolio Standard Procurement Plan*, R.18-07-003 (Apr. 21, 2022).

There is intended to be no change to the schedule for the Commission's decision on the Market Offer Process.

III. PROTEST

1. PG&E Should be Required to Align the Products Offered in its Market Offer Contract to Those Offered by SCE and SDG&E

PG&E's Market Offer Contract is a generic form document that offers a product comprising a "slice" of PG&E's total PCIA-eligible RPS portfolio remaining after the voluntary allocations. This slice will include a mixture of PG&E's bundled and unbundled resources, and the composition of that mixture may change during the term of the Market Offer Contract due to portfolio optimization efforts and the termination of existing contracts. As a result, bidders in the market offer will be required to place a value on a mixture of resources without any guarantee that the composition of the pool of resources on which they bid will not change. The Market Offer Contract as currently written will make it impossible for bidders to establish the ultimate value of the product offered.

In contrast, SCE and SDG&E offer products in their market offer pro forma contracts that contain a "slice" of resources based on their PCC classifications (*i.e.*, bundled and unbundled RECs). Such products provide flexibility to parties and ensure the ability of parties to properly value the products. As such, the market offer process for SCE and SDG&E provides far greater certainty to bidders. PG&E should be required to align its product offerings in the market offer to those of SCE and SDG&E.

2. The Market Offer Contract Must Require PG&E to Provide LSEs With Timely Access to Meter Data

As CalCCA noted with respect to the Voluntary Allocation Contract, counterparties receiving energy and/or RECs from PG&E through the market offer process require timely access to data regarding their purchases for operational and planning purposes. Unlike a traditional "firm" contract for energy and/or RECs, the Market Offer Contract offers a varying quantity of energy and/or RECs based on actual generation from a "slice" of a pool of resources. Because this volume is inherently variable, information regarding amounts delivered is crucial.

PG&E receives initial data shortly after the delivery month. Counterparties require at least initial, non-binding meter data of the contract quantity as soon as reasonably practicable, but no later than fifteen (15) calendar days following the delivery month. The information is used for forecasting, portfolio management, as well as contract validation and administrative purposes. As CalCCA has also noted with respect to the Voluntary Allocation Contract, the disadvantage to CCAs from limited access to this generation data impedes both their ability to plan for their future needs, and to account for the purchase they are making on their customers' behalf. Ultimately, this additional uncertainty reduces the value of the associated RECs compared to what could be purchased under improved terms. CalCCA therefore requests that the

Commission require PG&E to provide preliminary, non-binding, forecast and meter data to a Market Offer counterparty within fifteen (15) calendar days of the end of each delivery month.

3. CalCCA Anticipates Additional Comments on the Market Offer Contract Following its Review of the Market Offer Process

As is true with respect to the Voluntary Allocation Contract, the terms of the Market Offer Contract are extremely important to potential counterparties considering participating in the offer. To facilitate the portfolio optimization efforts ordered by the Commission in the Phase 2 Decision and ensure the success of the VAMO process, the Market Offer Contract must be carefully reviewed in the context of the actual offer. It would be unfortunate if successful completion of VAMO is hampered by terms that are commercially unreasonable, or that fail to account for the specifics of the products actually offered through the Market Offer Process.

In addition, without understanding the context of the Market Offer Contract in terms of the Market Offer Process and PG&E's intentions regarding any other future firm or non-firm REC sales, fully evaluating the Market Offer Contract is impossible. For these reasons, CalCCA anticipates additional comments on the Market Offer Contract following its full review of the Market Offer Process, and any supplements to this Advice Letter filed as noted above.

IV. CONCLUSION

CalCCA thanks the Energy Division for its review of this Protest, and strongly advises against approval of the Market Offer Contracts until the issues set forth herein are addressed.

Respectfully,

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

Evelyn Kahl

Evelyn Kahl
General Counsel and Director of Policy

cc via email:
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**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	Rulemaking 17-06-026

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING REGARDING
MARKET PRICE BENCHMARKS**

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On behalf of
California Community Choice Association

April 28, 2022

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SUMMARY OF RECOMMENDATIONS

- ✓ The Commission should adopt Energy Division Staff's Plan to exclude the Renewables Portfolio Standard (RPS) Voluntary Allocations when calculating the RPS Market Price Benchmark (MPB).

- ✓ The Commission should monitor the liquidity of the bi-lateral RPS market to ensure a stable RPS MPB.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	Rulemaking 17-06-026

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING REGARDING MARKET PRICE BENCHMARKS

The California Community Choice Association[1] (CalCCA) submits these Comments in response to the *Administrative Law Judge's Ruling Regarding Market Price Benchmarks* (Ruling), issued April 18, 2022.

I. INTRODUCTION

The Ruling requests comments on the *Energy Division Staff Implementation Plan to Address Renewable Portfolio Standard Voluntary Allocation Transactions in Market Price Benchmark Calculations* (Staff Plan).[2] Decision (D.) 21-05-030 establishes the Voluntary Allocation and Market Offer (VAMO) process for renewables portfolio standard (RPS) resources.[3] Through the Voluntary Allocation, non-investor-owned utility (IOU) load-serving

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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] Ruling, Attachment A.

[3] D.21-05-030, *Phase 2 Decision on Power Charge Indifference Adjustment Cap and Portfolio Optimization,* R.17-06-026 (May 20, 2021).

entities (LSEs) may accept allocations of RPS-eligible energy from the IOU portfolio. The IOUs and non-IOU LSEs will enter into contracts for the Voluntary Allocations, and the non-IOU LSE will pay for the resources at the applicable year's MPB.

The Commission should adopt the Staff Plan, which proposes to exclude the Voluntary Allocations for purposes of future MPB calculations. Removing Voluntary Allocation transactions from the MPB calculation will result in the MPB accurately reflecting market prices and dynamics. In addition, as the Voluntary Allocation transactions will be contracted for at the applicable year's MPB, such transactions should be excluded to ensure the new calculation is not weighted by a previous year's MPB. On an ongoing basis to ensure a stable RPS MPB, the Commission should monitor the impact of the Voluntary Allocation process on the liquidity of the bi-lateral RPS market.

II. THE COMMISSION SHOULD ADOPT THE STAFF PLAN TO EXCLUDE VOLUNTARY ALLOCATIONS FROM THE CALCULATION OF THE MPB

The Commission should adopt the Staff Plan to exclude Voluntary Allocations from the calculation of the MPB. Excluding the Voluntary Allocation transactions will (1) ensure the RPS MPB reflects market prices and dynamics; and (2) ensure the following year's MPB is not weighted by the previous year's MPB. While the Staff Plan creates a risk that the MPB is set by a shallow market for RPS attributes, adequate Commission monitoring of the impact of excluding Voluntary Allocations from the calculation can ensure a stable RPS MPB.

A. Voluntary Allocations are Not Market Sales

Voluntary Allocations are simply not market sales. Under the Voluntary Allocation, each IOU will allocate "slices" of its entire RPS portfolio to non-IOU LSEs in its service territory.[4] The IOU and the non-IOU LSE will enter into a contract for the Voluntary Allocation, in which

[4] D.21-05-030 at 58, Conclusion of Law 7(a), and 63, Ordering Paragraph 2(a).

the non-IOU LSE will pay for their "slice" at the applicable year's MPB. The allocation allows departed load customers who already pay for the above-market costs of the resources in question to receive the RPS benefits from those resources. As the IOUs explain, "[a]llocation of the [RECs] under the Voluntary Allocation process simply allows the . . . RECs to follow the departed load customers who are already obligated to pay for them."[5] The Voluntary Allocation "includes none of the hallmarks of a standard sales transaction – it does not require the IOU and LSEs to negotiate terms related to price, counterparty (only LSEs serving departed load are eligible) or quantity."[6] Thus, the Staff Plan will appropriately exclude allocations that are not true market-based sales.

B. Voluntary Allocations Should Not Impact the Market Price Benchmark Calculation

The MPB should not be impacted by the Voluntary Allocations, which will not reflect a true measure of what the market is willing to pay for RPS attributes. The RPS Adder in the MPB represents the value of transactions from solicitations and resulting bi-lateral contracting, which are generally transactions for RPS output from a particular resource or a subset of later-determined resources in the IOUs' portfolios. These transactions are fundamentally different than the Voluntary Allocations, which are transacted based on the administratively set previous year's MPB. The calculation of the new MPB should not be influenced or weighted by the previous year's MPB.

5 *Joint Motion of Southern California Edison Company (U 338-E), Pacific Gas and Electric Company (U 39-E) and San Diego Gas & Electric Company (U 902-E) to Amend Scoping Memorandum to Accommodate Voluntary Allocation Structure*, R.18-07-003 (Dec. 8, 2021) (Joint IOU Motion), at 7.

6 *Id.*

C. The Commission Should Monitor the Impact of Excluding the Voluntary Allocations in the MPB Calculation

The Staff Plan will result in the possibility of the RPS MPB being set through an illiquid, shallow bi-lateral market for RPS attributes. For example, in years in which RPS prices are particularly high, *i.e.*, when LSEs may be motivated to take their Voluntary Allocations instead of seeking a lower price in subsequent solicitations, there may be few bi-lateral transactions outside of the Voluntary Allocations. This could potentially lead to increased volatility in the calculation of the RPS Adder. However, liquidity in the market may change from year to year on account of myriad different factors. It is difficult to predict in advance the likelihood of the risk of illiquidity, especially in light of increasing RPS requirements that may foster more robust market participation outside of the allocations. Nonetheless, the Commission should monitor the impact of the Voluntary Allocation process on the liquidity of the bilateral RPS market to ensure a stable RPS Adder. Such monitoring could take a form similar to that of the *ex post* analysis the Commission required in D.22-01-023 to analyze the impact of moving from a November Update to an October Update.[7]

[7] *See* D.22-01-023, *Decision Resolving Phase 2 Issues Related to Energy Resources Recovery Account Proceedings,* R.17-06-026 (Jan. 27, 2022), at 27, Ordering Paragraph 2 (stating that "[b]y March 1, 2024, the staff of the California Public Utilities Commission is authorized to file and serve upon the service list of this proceeding and any successor proceeding an analysis of the impact of changing the [PCIA MPB] release date on forecast accuracy.").

III. CONCLUSION

For all the foregoing reasons, CalCCA respectfully supports the Staff Plan and looks forward to an ongoing dialogue with the Commission and stakeholders with regard to ensuring liquidity in the RPS market post Voluntary Allocation implementation.

Respectfully submitted,

Tim Lindl
KEYES & FOX LLP

On behalf of
California Community Choice Association

April 28, 2022

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program.	R.18-07-003

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENTS ON VOLUNTARY ALLOCATIONS OF RENEWABLES PORTFOLIO STANDARD RESOURCES AND PORTFOLIO CONTENT CATEGORY ISSUES

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On behalf of
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April 28, 2022

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SUMMARY OF RECOMMENDATIONS

- ✓ The California Public Utilities Commission (Commission) should find that the allocation of renewable energy credits (RECs) to non-investor-owned utility (IOU) load-serving entities (LSEs) pursuant to the Voluntary Allocation process are not “resales” that require reclassification of their Portfolio Content Category (PCC).
- ✓ Subsequent resales of the RECs obtained through the Voluntary Allocation process should be reclassified for PCC purposes; and
- ✓ The Commission should adopt the Voluntary Allocation Market Offer (VAMO) schedule proposed by CalCCA.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program.	R.18-07-003

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENTS ON VOLUNTARY ALLOCATIONS OF RENEWABLES PORTFOLIO STANDARD RESOURCES AND PORTFOLIO CONTENT CATEGORY ISSUES

The California Community Choice Association[1] (CalCCA) submits these Comments in response to the Administrative Law Judge's Ruling Seeking Comments on Voluntary Allocations of Renewables Portfolio Standard Resources and Portfolio Content Category Issues (Ruling), issued on April 18, 2022.

I. INTRODUCTION

Decision (D.) 21-05-030 (Phase 2 Decision) in the Power Charge Indifference Adjustment (PCIA) proceeding establishes new requirements for IOU portfolio optimization, including the VAMO. The Phase 2 Decision leaves details regarding the implementation of VAMO to this Renewables Portfolio Standard (RPS) proceeding.[2] The Ruling requests party

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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] D.21-05-030, *Phase 2 Decision on Power Charge Indifference Adjustment Cap and Portfolio Optimization,* R.17-06-026 (May 20, 2021) (Phase 2 Decision) at 37 (proposing a timeline for the first VAMO, "subject to adjustments in the RPS proceeding").

comments on two of these details: (1) Portfolio Content Category (PCC) classification following the Voluntary Allocation; and (2) the VAMO timeline.[3]

The Phase 2 Decision creates the Voluntary Allocation process in which non-IOU LSEs serving customers previously served by the IOU are allocated a "slice" of the IOU's PCIA-eligible RPS resources, including PCC 0 resources. The compliance "value" of such resources to the non-IOU LSEs depends greatly on the PCC classification such resources receive upon allocation. As noted in the Ruling, the IOUs filed a Joint Motion on December 8, 2021 requesting clarification that the PCC classification of RECs will not be changed when those RECs are directly allocated under the Voluntary Allocation process.[4] CalCCA filed a response to the Joint Motion on December 23, 2021, supporting the Joint IOU's position.[5] CalCCA agrees with the Joint IOUs that the intent of the Phase 2 Decision is to allow the recipient LSEs to "step into the shoes" of the IOUs with respect to the allocated resources. There is no language in statutes or Commission decisions regarding PCC classification that prevents LSEs from receiving in the allocation the classification the resources receive while they are held by the IOU.

With respect to the timeline, the VAMO schedule was originally introduced in Table 2 of the Phase 2 Decision,[6] which anticipates possible changes to the timeline: "[w]e expect to implement the initial RPS VAMO . . . as follows, *subject to adjustments in the RPS*

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[3] As noted in the Ruling, PCC 0 RECs (*i.e.,* RECs generated pursuant to contracts executed before June 1, 2010) count in full for RPS compliance without regard to the quantitative requirements for the use of each PCC established by Public Utilities Code § 399.16(c). Ruling at 3.

[4] Ruling at 2; *Joint Motion of Southern California Edison Company (U 338-E), Pacific Gas and Electric Company (U 39-E) and San Diego Gas & Electric Company (U 902-E) to Amend Scoping Memorandum to Accommodate Voluntary Allocation Structure*, R.18-07-003 (Dec. 8, 2021) (Joint Motion) at 6.

[5] *California Community Choice Association's Response to Joint Motion of Southern California Edison Company (U 338-E), Pacific Gas and Electric Company (U 39-E) and San Diego Gas & Electric Company (U 902-E) to Amend Scoping Memorandum to Accommodate Voluntary Allocation Structure,* R.18-07-003 (Dec. 23, 2021) (CalCCA Response to Joint Motion).

[6] Phase 2 Decision, Table 2 at 37.

proceeding.”[7] Since the Phase 2 Decision, certain milestones in the Phase 2 Decision have been missed, and many uncertainties and questions with respect to the requirements for the VAMO remain. For example, the IOUs were required by the Phase 2 Decision to “inform LSEs of their potential Voluntary Allocation shares” in February 2022.[8] Many community choice aggregators (CCAs), however, have yet to receive adequate information regarding their potential Voluntary Allocation shares.[9] Several filings and orders have also been issued that have revised the schedule in piecemeal fashion, but uncertainties regarding the VAMO schedule persist.

The outstanding issues on PCC classification and the schedule uncertainties currently present obstacles for non-IOU LSEs considering whether to elect to take their Voluntary Allocations.[10] Accordingly, CalCCA recommends that the Commission:

✓ Find that the allocation of RECs to non-IOU LSEs pursuant to the Voluntary Allocation process are not “resales” that require reclassification;

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7 *Id.* at 37.

8 *Id.*, Table 2 at 38.

9 For example, SDG&E unilaterally informed LSEs by email that it would revise its schedule to provide the forecast by April 29, 2022. PG&E states on its website dedicated to VAMO that it plans to “inform[] eligible LSEs of initial forecast allocation shares for Voluntary Allocation” on May 16, 2022, when it files its ERRA Forecast Application. However, by letter dated April 21, 2022 to the Executive Director of the Commission, PG&E requested an extension to May 31, 2022 to file its ERRA Forecast Application. PG&E’s request for extension was granted by the Executive Direct by letter dated April 27, 2022. PG&E has yet to inform CCAs of a change to the date it will inform of the initial forecast allocation shares, and has not updated its VAMO website to reflect the change to May 31, 2022. PG&E’s VAMO website is located at https://www.pge.com/en_US/for-our-business-partners/energy-supply/electric-rfo/wholesale-electric-power-procurement/2022-rps-voluntary-allocation.page?WT.mc_id=Vanity_rfo-2022-rps-voluntary-allocation

10 In addition, currently under suspension are the IOU Advice Letters proposing pro forma contracts for the Voluntary Allocation. *See* PG&E Advice 6517-E (Feb. 28, 2022), *suspended up to 120 days* (Mar. 29, 2022), *supplemented by* PG&E Advice 6517-E-A (Apr. 11, 2022); SCE Advice 4732-E (Feb. 28, 2022), *supplemented by* SCE Advice 4732-E-A (Mar. 18, 2022), *suspended up to 120 days* (Mar. 29, 2022); SDG&E Advice 3962-E (Feb. 28, 2022), *suspended up to 120 days* (Mar. 29, 2022). CalCCA filed protests to all three Advice Letters regarding unacceptable terms in the pro forma contracts. *See CalCCA Protest to PG&E AL 6517-E* (Mar. 21, 2022), *CalCCA Protest to SCE AL 4732-E* (Mar. 21, 2022), *CalCCA Protest to SDG&E AL 3962-E* (Mar. 21, 2022). Resolution of the outstanding issues with respect to the pro forma contracts is also necessary to provide certainty to parties considering accepting their Voluntary Allocations.

- ✓ Find that subsequent resales of the RECs obtained through the Voluntary Allocation process should be reclassified; and
- ✓ Adopt the VAMO schedule proposed by CalCCA.

II. CALCCA RESPONSES TO QUESTIONS 1-3

A. RULING QUESTION 1: *Should the Voluntary Allocation under the VAMO process be considered "resales" for purposes of determining PCC classifications? Why or why not? (a) If the Voluntary Allocation should be considered a resale, how should PCC classification for pre-June 1, 2010 RPS contract RECs be determined? (b) If the Voluntary Allocation is not considered a resale, how should PCC classification for pre-June 1, 2010 RPS contract RECs be determined?*

Voluntary Allocations should not be considered resales for purposes of determining PCC classifications. A Voluntary Allocation is not a traditional "sales" transaction – it is instead a Commission-approved and overseen regulatory mechanism to transfer to departed load customers the benefits of resources procured on their behalf. In addition, no statutes or Commission precedent require Voluntary Allocations to be treated as resales, or otherwise address this unique situation. As a result, RECs for pre-June 1, 2010 RPS contracts should retain the PCC classification held by the IOU prior to the Voluntary Allocation to the non-IOU LSE.

1. The Voluntary Allocations Under the VAMO Process are the Product of a Regulatory Mechanism Rather Than a "Sales" Transaction

CalCCA has and continues to support the Joint IOUs' position that Voluntary Allocations are not comparable to resale arrangements, and therefore PCC classifications should not be changed because the resource is allocated. As the IOUs discuss in detail in the Joint Motion, the Voluntary Allocation process is not a standard sales transaction.[11] The Voluntary Allocation is a Commission-approved and overseen regulatory mechanism, not a sale. It is intended to transfer the value of attributes to the parties on whose behalf the original contracts were procured. As the

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11 Joint Motion at 6-9.

IOUs have explained, "[a]llocation of the [RECs] under the Voluntary Allocation process simply allows the value of [Power Content Category] 0 RECs to follow the departed load customers who are already obligated to pay for them."[12] The Voluntary Allocation is a specific response to a unique challenge: ensuring bundled and departed load customers each bear their share of costs, and enjoy their share of benefits, of resources purchased on their behalf.

Voluntary Allocations bear none of the hallmarks of a traditional "sales" transaction. The product offered is a unique "slice" of the IOU's PCIA-eligible RPS portfolio, and the price to be paid is not subject to negotiation. Only certain counterparties (i.e., the non-IOU LSEs serving departed customers for whom the RECs were procured) are even eligible to participate, and their level of participation is fixed by the Phase 2 Decision. Under the Voluntary Allocation, the recipient LSEs have no contact with the original seller, and the underlying contract itself remains untouched, including its term. Voluntary Allocations do not bear the hallmarks of traditional sales because the allocations are intended to accomplish a different, and complex, set of objectives.

2. Statute and Commission Precedent do Not Require Voluntary Allocations to be Treated as Resales

Permitting Voluntary Allocations to retain the original PCC classification of the original holder does not, as has been argued by TURN and CUE, fail "to conform to Commission precedent implementing the governing statutory requirements."[13] In addition, TURN and CUE's arguments that the Joint IOUs "seek to override [the Phase 2 Decision] and relitigate issues already resolved in that decision"[14] are not consistent with the actual findings of the Phase 2

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12 *Id.* at 7.

13 *Response of The Utility Reform Network and the Coalition of California Utility Employees to the Joint Motion of Southern California Edison Company, Pacific Gas and Electric Company and San Diego Gas & Electric Company to Amend Scoping Memorandum to Accommodate Voluntary Allocation Structure,* R.18-07-003 (December 23, 2021) (TURN/CUE Response) at 1.

14 *Id.* at 3.

Decision. TURN is correct that the Commission has previously considered the question of whether long-term treatment can be retained if contracts are "repackaged" as short-term transactions for RPS compliance.[15] But notwithstanding TURN's repeated efforts to liken them,[16] allocations under VAMO structured to redistribute the costs and benefits of the IOUs' RPS portfolios are simply not resales. Neither statute nor Commission decision has determined that they are. In fact, the implication that there has been a decision on this point is incorrect. TURN and CUE's arguments are unpersuasive and rely on precedent that does not support their positions.

a. Commission Precedent Finding that Unbundling of Energy and RECs Results in PCC Reclassification Does Not Apply to the Voluntary Allocation

TURN and CUE make a general pronouncement that the IOU's proposal "fails to conform to Commission precedent implementing the governing statutory requirements"[17] because "[p]ursuant to D.11-12-052, any resale of energy and/or RECs associated with [contracts executed prior to June 1, 2010] must be assigned the PCC that would apply if the resource was first contracted after June 1, 2010."[18] TURN and CUE's reliance on D.11-12-052 is disingenuous. TURN and CUE quote the following sentence from D.11-12-052 as support for their argument (emphasis added):

> If any RECs from a contract signed prior to June 1, 2010, are *unbundled and sold separately* after June 1, 2010, the underlying energy may not be used for RPS compliance; and the unbundled RECs will be counted in accordance with the limitations on § 399.16(b)(3), as set out in § 399.16(c)(2).[19]

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15 *See* D.12-06-038, *Decision Setting Compliance Rules for the Renewables Portfolio Standard Program,* R.11-05-005 (June 21, 2012) at 44.

16 *See, e.g., Reply Comments of The Utility Reform on the Proposed Phase 2 Decision of ALJ Wang on Power Charge Indifference Adjustment Cap and Portfolio Optimization*, R.17-06-026 (May 3, 2021) at 2.

17 TURN/CUE Response at 1.

18 *Id.* at 3.

19 D.11-12-052, *Decision Implementing Portfolio Content Categories for the Renewables Portfolio Standard Program,* R.11-05-005 (Dec. 15, 2011) at 62.

But this language does not support their preferred reading. TURN and CUE would have us believe the resale is the key to changing the PCC classification. However, the sentence makes clear it is the fact of the *unbundling* and *separate* sale of energy and RECs that changes the classification, not the resale. In fact, D.11-12-052's Conclusions of Law and Ordering Paragraphs make this point. Conclusion of Law 24 states that RECs from PCC 0 contracts that are "unbundled" and sold separately are subject to reclassification. [20] Ordering Paragraph 17 repeats this same language.[21] Thus, TURN/CUE's argument is misplaced and should be rejected.

b. The Phase 2 Decision's Holding Regarding Long-Term Contracting Requirements Does Not Apply to PCC Classification on Voluntary Allocation

TURN and CUE also argue that the Phase 2 Decision holds "that the allocation of contracts under the VAMO should be treated as a resale for purposes of compliance with the long-term contracting requirements outlined in §399.13(b)." [22] This, again, is simply not the case.

The language cited by TURN and CUE in support of this position actually concerns the treatment of long-term allocations under the long-term contracting requirements in § 399.13(b).[23] The Phase 2 Decision requires long term allocations to last for a specified period of years to receive "long-term" treatment under the RPS requirements. But the Phase 2 Decision does not even address, let alone dispose of the underlying issue – whether or not the allocations are resales for PCC classification purposes.

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20 *Id.* at 75.
21 *Id.* at 82-83.
22 TURN/CUE Response at 3.
23 Phase 2 Decision at 22 ("[w]e conclude that providing an opportunity for LSEs to receive long-term credit for RPS contracts that have less than 10 years remaining through Voluntary Allocations would violate Section 399.13(b). Thus, generation from IOUs' long--term contracts in an allocation with less than 10 years remaining will be included in short-term allocations.").

TURN and CUE's underlying concern seems to be what they term "perceived loopholes established for VAMO resources" that could be created if PCC classifications transfer to the recipients of the Voluntary Allocation.[24] But there are no "loopholes" precisely because there is no statutory language or Commission decision directly addressing the question of PCC classification in the context of a Voluntary Allocation. This issue has simply not been addressed. In addition, the Commission would not be creating a "loophole" by finding that the allocations are not resales because of their unique status as a Commission created mechanism rather than an actual sale.

3. Retaining the PCC Classification of a Product Allocated Through the Voluntary Allocation Implements the Intent of the Phase 2 Decision

The Phase 2 Decision addresses portfolio optimization and ensuring cost indifference for bundled and unbundled customers. CalCCA agrees with the IOUs that the purpose of the Voluntary Allocation is to allow RPS procurement "to 'follow' customers who move from bundled service to [CCA] or [Direct Access] service *without alteration of the benefits conveyed by such procurement*."[25] Only by allowing the PCC classification to be retained can the Commission comply with the Phase 2 Decision's Conclusion of Law 10: "[i]t is reasonable and consistent with existing Commission decisions on renewable energy attributes to preserve the bundled nature of energy and compliance attributes through [VAMO] sales contracts."[26] Retaining the PCC Classification best implements the Commission's intent to maintain the "bundled nature of energy and compliance attributes" for departed customers through the Voluntary Allocation.

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24 TURN/CUE Response at 3.
25 Joint Motion at 3 (emphasis added).
26 Phase 2 Decision at 60, Conclusion of Law 10.

For all of the reasons set forth above, Commission should adopt the Joint IOUs' recommendation that PCC classifications be retained following the Voluntary Allocation.

B. RULING QUESTION 2: *If the Commission determines that PCC-0 designation should be retained for this initial Voluntary Allocation from IOUs to LSEs, how should subsequent resale of these contracts by an LSE affect their REC PCC classification?*

1. Subsequent Resales of Contracts by LSEs After the Voluntary Allocation Should Result in Reclassification

CalCCA agrees with the Joint IOUs that the allocation recipient LSE's PCC 0 classification should be reclassified on subsequent downstream transfer of the REC from the recipient LSE to a third party. As set forth in the Joint IOU Motion, "post-allocation resale of a PCC 0 REC by an IOU or a non-IOU LSE would alter the classification of the PCC 0 REC to either PCC 1, PCC 2, or PCC 3 according to the same rules that apply today to any resale."[27]

C. RULING QUESTION 3: *While D.21-05-030 (Table 2) provides a schedule for the VAMO process, it also authorizes the RPS proceeding to adjust the timing and process for the filings. Does our consideration of Voluntary Allocations and PCC classification issues necessitate a change in that schedule? If so, propose a revised schedule and justification for the need to make changes.*

1. The VAMO Timeline Proposed in the Phase 2 Decision Should be Revised for the Voluntary Allocation to Proceed Only After Commission Resolution of the PCC Classification and IOU Pro Forma Contract Term Issues

The Commission's consideration of Voluntary Allocations and PCC classification necessitates changes to the VAMO process schedule. As noted above, the compliance "value" of such resources to LSEs depends greatly on the PCC classification that such resources receive. LSEs will therefore be reluctant to elect their allocation until the PCC classification issue is resolved. In addition, and as noted in CalCCA's Protests to the IOU Advice Letters proposing

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[27] Joint Motion at 4.

their Voluntary Allocation pro forma contracts,[28] certain IOU contract terms present uncertainties to parties which must be resolved prior to LSEs electing to sign the contracts. Therefore, until both the PCC classification issues and the protests on IOU contract terms are resolved, LSEs are reluctant to participate in the Voluntary Allocation process.

Set forth below is a proposed schedule for the entire VAMO process, with the goal of both Voluntary Allocation and Market Offer deliveries beginning January 1, 2023. The proposed schedule would provide time for CCAs to pursue approval of VAMO contracts, once notified of their allocation share from the IOUs, from their governing boards. Under the schedule, such approval could be sought by the CCAs after receiving guidance from the Commission on the PCC classification issue, and from Energy Division on both the Voluntary Allocation pro forma contract issues and the Market Offer pro forma contract and process issues.

Finally, the schedule for Voluntary Allocation contracting should be revised from the schedule set forth in Phase 2, Table 2. The Ruling cites Table 2 as requiring "Voluntary Allocation contracting [to] commence 21 days after Commission approval of final 2022 RPS Plans."[29] However, approval of the final 2022 RPS Plans will likely not occur until at least February 2023. As noted in the Commission's April 11, 2022 Ruling regarding issues and schedule for the 2022 RPS Plans, Voluntary Allocation and Market Offer deliveries are anticipated to begin in January 2023.[30] Therefore, as set forth in CalCCA's proposed schedule below, contracting for both the Voluntary Allocation and Market Offer must be complete well in advance of January 2023.

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[28] *See infra,* n. 10.

[29] Ruling at 2 (citing Phase 2 Decision at 38, Table 2).

[30] *Assigned Commission and Assigned Administrative Law Judge's Ruling Identifying Issues and Schedule of Review for 2022 Renewables Portfolio Standard Procurement Plans and Denying Joint IOUs' Motion to File Advice Letters for Market Offer Process,* R.18-07-003 (Apr. 11, 2022) at 13.

Table 1: CalCCA Proposed VAMO Schedule

VAMO Milestone	Date
Party Comments submitted – PCC Classification/VAMO Schedule	April 28, 2022
IOU Joint Market Offer (MO) Process Filing	May 2, 2022
Proposed Decision – PCC Classification/VAMO Schedule	May 6, 2022 (Shortened Comments Period – Comments 5/13, Replies 5/18)
IOU Individual MO Process -Confidential Filing	May 16, 2022
IOUs Complete Process of Informing LSEs of Voluntary Allocation (VA) Shares	May 31, 2022
Final Decision – PCC Classification and VAMO Schedule	June 2, 2022 (Voted on at Commission meeting)
Party Comments – IOU MO Process Filing	June 6, 2022
Energy Division Action on Tier 2 Voluntary Allocation Pro Forma Contract (VA) Advice Letters	June 9, 2022
Replies – IOU MO Process	June 13, 2022
IOUs, Small Utilities, ESPs and CCAs file Draft 2022 Annual RPS Procurement Plan Filings	July 1, 2022
Proposed Decision – MO Process	July 18, 2022
IOUs and LSEs complete process of determining interest in VA elections and sign VA contracts	By July 29, 2022
Comments – MO Process PD	August 8, 2022
Replies – MO Process PD	August 15, 2022
IOUs submit Motions to Update Draft 2022 RPS Procurement Plans	August 15, 2022
Final Decision – MO Process	September 15, 2022 (Voted on at Commission meeting)
Energy Division Action on Tier 2 MO Pro Forma Contract Advice Letters	September 29, 2022
IOU/LSE MO Contracting Concludes	November 15, 2022
Commence VA and MO Deliveries	January 1, 2023

III. CONCLUSION

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

Respectfully submitted,

Evelyn Kahl

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

April 28, 2022

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

QUARTERLY DISADVANTAGED COMMUNITIES GREEN TARIFF AND COMMUNITY SOLAR GREEN TARIFF PROGRAMS REPORT OF MARIN CLEAN ENERGY FOR PERIOD JANUARY 1 – MARCH 31, 2022

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April 29, 2022

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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

QUARTERLY DISADVANTAGED COMMUNITIES GREEN TARIFF AND COMMUNITY SOLAR GREEN TARIFF PROGRAMS REPORT OF MARIN CLEAN ENERGY FOR PERIOD JANUARY 1 – MARCH 31, 2022

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

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

[1] Resolution E-4999, *Approving with Modifications Tariffs to Implement the Disadvantaged Communities Green tariff and Community Solar Green Tariff Programs*, OP 1(f) at p.63.

D.18-06-027 authorized Community Choice Aggregators ("CCAs") to offer DAC-GT and CS-GT programs to their customers.[2] As program administrators, CCAs are subject to the same reporting requirements as investor-owned utilities ("IOUs"). Hence, MCE hereby submits a quarterly report covering the period of January 1 to March 31, 2022, attached hereto as Attachment A.

Respectfully submitted,

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Dated: April 29, 2022

[2] D.18-06-027, *Alternate Decision Adopting Alternatives to Promote Solar Distributed Generation in Disadvantaged Communities*, OP 17 at p.104.

ATTACHMENT A

QUARTERLY DISADVANTAGED COMMUNITIES GREEN TARIFF AND COMMUNITY SOLAR GREEN TARIFF PROGRAMS REPORT FOR JANUARY 1, 2022 TO MARCH 31, 2022 OF MARIN CLEAN ENERGY

Pursuant to Decision 18-06-027 ("Decision")[1] and in accordance with Resolution E-4999,[2] Marin Clean Energy ("MCE") files this quarterly report on the Disadvantaged Communities Green Tariff ("DAC-GT") and Community Solar Green Tariff ("CSGT") programs for the period January 1, 2022 to March 31, 2022. MCE reports on the following program metrics as required by Resolution E-4999:

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

1. Capacity Procured and Online

The DAC-GT program (branded as MCE's "Green Access" program) has a capacity cap of 4.64 MW. The CS-GT program (branded as MCE's "Community Solar Connection" program) has a capacity cap of 1.28 MW.[4]

On August 27, 2021, MCE launched the first DAC-GT and CSGT solicitation, with bids due on November 19, 2021. MCE received bids for the DAC-GT program and entered into two PPAs totaling 4.64 MW. The PPAs consist of a 4.4 MW solar facility and an adjacent .24 MW solar facility. The total combined capacity of these two projects fills MCE's Green Access program capacity. The resources are anticipated to be online by December 2023. MCE received no bids for the CSGT program. MCE will issue an another RFO for CSGT in the third quarter of 2022. As such, as of the date of this report MCE does not have any new capacity procured or online under either the DAC-GT or the CSGT program.

Enrolled customers under the DAC-GT program are currently being served by "interim resources" that meet the eligibility requirements of the programs in accordance with Resolution E-4999.[5]

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

MCE is serving DAC-GT customers with solar generation from the Goose Lake project, located at 15004 Corcoran Rd., Lost Hills, CA 93249 in DAC census tract 6031001300.

2. Participating Customers

The DAC-GT and CSGT programs provide a 20% bill discount to eligible customers located in DACs. DACs are defined under D.18-06-027 as communities that are identified in the CalEnviroScreen ("CES") tool as among the top 25 percent of census tracts statewide, plus the census tracts in the highest five percent of CES' Pollution Burden that do not have an overall CES score because of unreliable socioeconomic or health data.[6]

The DAC-GT program is available to residential customers who live in DACs, receive generation service from MCE, and meet the income eligibility requirements for the CARE program and/or the FERA program.[7] In MCE AL 42-E-A, MCE opted to auto-enroll eligible customers that live in one of the top 10% of DAC census tracts statewide in MCE's service area if they meet certain criteria.[8]

The CSGT program is available to residential customers who live in DACs (as defined by D.18-06-027) and receive generation service from MCE. Non-residential customers are not eligible to participate, except for the project sponsor. A solar generation project supporting the program must be located within five miles of the participating customers' census tract. At least fifty percent of a project's capacity must be reserved for low-income customers, defined as those meeting the income qualifications for either the CARE or FERA programs.[9]

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

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

	DAC-GT	**CSGT**
Customers Subscribed as of 3/31/2022	3,012	0

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

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

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

Census Tract	County	City (closest by proximity)	Count
6013312000	Contra Costa	Pittsburgh	292
6013365002	Contra Costa	Richmond / San Pablo	606
6013376000	Contra Costa	Richmond	122
6013377000	Contra Costa	Richmond	957
6013379000	Contra Costa	Richmond	766
6013382000	Contra Costa	El Cerrito	73
6095250701	Solano	Vallejo	58
6095250900	Solano	Vallejo	138
Grand Total			**3,012**

3. CARE and FERA Customer Enrollments

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

4. CSGT Semi-Annual Project Details

As indicated above, MCE received no bids in its 2021 solicitation for CSGT projects, and as a result has enrolled no customers in CSGT. As such, MCE has no project details to report at this time.