NOVEMBER FILINGS

**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 ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENTS ON PORTFOLIOS TO BE USED IN THE 2021-22 TRANSMISSION PLANNING PROCESS

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November 10, 2020

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

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COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING
SEEKING COMMENTS ON PORTFOLIOS TO BE USED IN THE 2021-22
TRANSMISSION PLANNING PROCESS**

The California Community Choice Association (CalCCA)[1] submits these Comments in response to the *Administrative Law Judge's Ruling Seeking Comments On Portfolios To Be Used In The 2021-22 Transmission Planning Process,* issued on October 20, 2020 (ALJ Ruling).

I. INTRODUCTION

The ALJ Ruling seeks comments on three attachments: Framework for TPP Portfolio Selection; Descriptions of the Proposed Portfolios for the 2021-2022 TPP; and Methodology for Resource-to-Busbar Mapping and Assumptions for the 2021-2022 TPP. CalCCA supports the general frameworks proposed with the following recommendations:

1. Submit Policy-Driven Sensitivity #1 as the Base Case to reflect LSE and stakeholder preferences for a more aggressive decarbonization pathway.

[1] California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, CleanPowerSF, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, 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, Silicon Valley Clean Energy, Solana Energy Alliance, Sonoma Clean Power, Valley Clean Energy, and Western Community Energy.

2. Revise the Busbar Mapping methodology for battery storage to align with updated CAISO processes for deliverability assessment for storage resources.

Responses to Questions for Parties

1. Please Comment on Attachment A, the Framework for TPP Portfolio Selection, and recommend any changes that should be made.

CalCCA appreciates the thoughtful Framework put forward by Commission staff, and offers the following recommendations to ensure the TPP portfolios selected are aligned with LSEs' procurement plans.

CalCCA supports the proposed baseline reconciliation process outlined in "Modeling Assumptions: 2020-2021 TPP Report Release 1" and recommends that Overarching Principle 2 be modified as follows to enshrine the importance of updating the Reference System Portfolio (RSP) with new information provided from LSEs' plans:

> *Portfolios selected for the upcoming TPP cycle should reflect the most up-to-date RSP or PSP portfolios adopted by the Commission, updated with new LSE baseline contracts and other information from LSE IRPs and updates when possible.*

In addition to enshrining the inclusion of updating the baseline resource list, modifying Overarching Principle 2 as proposed would allow the Commission to consider other critical information received through LSE IRPs that was not available when selecting an RSP.

Specifically, this modification would be useful in addressing the unique portfolio selection issue in this IRP cycle resulting from D.20-03-028, which left open the Commission's ultimate preference between a 46 million metric ton (MMT) Preferred System Portfolio (PSP) or a 38MMT PSP. As discussed further in Question 2, there is ample justification for the Commission to adopt a PSP meeting a 38MMT emissions target, and, as a least regrets strategy, to transmit the Commission's current 38MMT portfolio as the Base Case for the 2021-2022 TPP. While not technically the adopted RSP, the 38MMT portfolio was given similar consideration and analysis as the 46MMT RSP and better reflects the procurement intent of LSEs. Modifying 2A as proposed would recognize this unique situation at a level of detail appropriate for guiding principles.

2. Do you recommend any changes to the proposed Base Case portfolio in Attachment B? If so, provide justification for your recommended changes.

Yes. In lieu of submitting the 46MMT RSP as the Base Case, CalCCA recommends submitting the 38MMT Policy-Driven Sensitivity #1 as the Base Case for several reasons:

- Most CCAs, along with other LSEs, indicated in their IRPs that they were planning on procuring resources in the future that would meet or exceed the 38 MMT target.
- There is increasing doubt that a 46MMT case will achieve California's decarbonization requirements as evidenced by the Commission's own Framing Study[2] and the California Energy Commission's Senate Bill (SB) 100 study[3].
- Recent analysis by CAISO indicates that the 38MMT portfolio may actually result in 41MMT of emissions in 2030[4], and may significantly *underestimate* the resource buildout necessary to maintain reliability.

In light of both LSE preferences and the policy justification for more aggressive decarbonization, submitting the 38MMT portfolio as the Base Case represents a "least regrets" strategy for the Commission to ensure transmission planning and development is available for the additional resources planned by LSEs and necessary for the achievement of state goals. To the extent the Commission ultimately adopts a 46MMT PSP which does not require the level of transmission development indicated by the submitted 38MMT portfolio, it is likely that any incremental

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2 California Public Utility Commission, Framing Study, Energy Division Presentation R.16-02-007 (Nov. 6, 2019) Attachment A.

3 L. Gill, California Energy Commission, "SB 100 Joint Agency Report: Charting a path to a 100% Clean Energy Future" Presentation, September 2, 2020, Docket 19-SB-100, TN#234549.

4 Comments of the CAISO. http://www.caiso.com/Documents/Oct23-2020_Comments-on-Integrated-Resource-Planning-R20-05-003.pdf at 5.

transmission would not go unused as the state continues to aggressively develop renewable resources on the path to 2045.

While recent reliability events have highlighted the importance of rigorously stress testing all portfolios, it is important to recognize that the 38MMT portfolio is not inherently less reliable than the 46MMT portfolio. Inversely, the 38MMT portfolio retains, in all years except 2030, the same baseline resource set as the 46MMT portfolio, but adds considerably more renewable generation and storage to the system. In light of CAISO's recent analysis indicating more buildout is necessary than what was indicated in the 38MMT portfolio, the Commission's submitted Base Case should plan for *at least* as much new resource development as the 38MMT portfolio.

3. Do you recommend any changes to the proposed Policy-Driven Sensitivity portfolios in Attachment B? If so, provide justification for your recommended changes.

Yes. Consistent with CalCCA's response to Question 2, CalCCA supports submission of the 46MMT RSP as Policy-Driven Sensitivity #1 given the policy justification to move forward with a 38MMT RSP as the Base Case.

5. Commission staff has proposed various improvements to the March 30, 2020 version of the Methodology (in Attachment C), and alongside these, has raised "alternative options" for consideration. Should any of the alternative options replace the proposed approach, or do you have other options that should be used instead? If so, clearly specify which topic(s) you are referring to and explain your reasoning.

The Commission should adopt the alternative option to additionally consider co-location of battery storage with wind resources. The justification for limiting battery co-locations to solar is that "Batteries co-located with solar are eligible for the federal Investment Tax Credit, but batteries co-located with wind would not receive the Production Tax Credit, and so staff expects that co-locating storage with wind would be less cost-effective."

There is considerable uncertainty regarding the future availability of the Investment Tax Credit and the set of resources to which it will apply. It is possible that federal legislation will enable similar tax treatment for standalone storage resources or even storage resources paired with wind. Further, studying the potential benefits of pairing storage with wind may provide useful analysis which may be beneficial for federal legislators considering such legislation.

6. Do you recommend any further changes to the non-battery mapping steps in Attachment C? What changes and why?

CalCCA recommends that staff ensure that the process be updated to be consistent with the recent deliverability changes instituted by the CAISO.

Specifically, in its recent review of deliverability assessment methodologies, CAISO has proposed new study scenarios that would align load levels with intermittent generation output[5]. The CAISO-proposed new study approach recognizes that, with a diverse grid, the peak reliability need is offset by the generation profiles under certain renewable conditions that mean significantly more of the resources are deliverable across the transmission system. As an example, storage resources producing during evening peak hours may not be competing with their paired solar systems for deliverability.

Implementation of CAISO's revised transmission deliverability methodology would result in accommodating more full capacity deliverability status (FCDS) resources in a given transmission area without triggering the need for transmission upgrades than would the existing California Public Utilities Commission's (CPUC) Energy Division methodology. The CAISO has found that under the

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[5] See http://www.caiso.com/InitiativeDocuments/RevisedDraftFinalProposal-GenerationDeliverabilityAssessment.pdf.

new methodology, several transmission upgrades identified using the current methodology would not be needed[6].

Implementing the CAISO's proposed methodology should not take considerable time and effort, as the CAISO could simply provide updated transmission capability information to the CPUC, allowing easy implementation inside of RESOLVE. CalCCA recommends that the CPUC use CAISO's transmission capability input estimates based upon CAISO's revised deliverability assessment methodology for all three TPP portfolios (i.e., the base case and the two sensitivity portfolios). This is important because some renewable and storage buildout areas are likely to see significant changes in the deliverable capacity numbers with CAISO's new methodology. These changes likely will result in identifying revised renewable portfolios that could utilize existing available transmission before triggering the need for a potentially different transmission upgrades in the CAISO 2021-2022 Transmission Plan. This will yield more cost-effective TPP portfolios.

7. Do you recommend any further changes to the battery mapping steps in Attachment C? What changes and why?

CalCCA generally supports staff's process for mapping battery storage, but suggests one modification to better align with the amount of storage expected to be co-located with solar, particularly in the early years.

Co-located Batteries: The CPUC staff-proposed approach appropriately provides priority to the co-located batteries, since these projects will be able to take advantage of synergies with the co-located solar resources. Staff proposes that the co-located batteries will be sized to a maximum of 60% of the solar resource. After the co-located battery assignments, stand-alone batteries will be assigned to substations without any solar resources using a certain order. CalCCA suggests that,

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[6] CAISO Generation Deliverability Assessment Methodology Issue Paper Stakeholder Call, May 2, 2019, at 21.

especially for the early years of the IRP, the storage should not be limited to 60% of the installed solar resources. CalCCA expects (and has observed) that parties will have a strong incentive to utilize the existing transmission capability that previously would have been utilized to deliver the solar output, and to transfer that deliverability to co-located storage resources. Limiting the storage to 60% of the solar resource will be unnecessarily restrictive.

LCR Area Batteries: CalCCA supports the CPUC staff's proposal for battery busbar mapping based on the assumption that the overall (non-4 hour) LCR area battery limits specified in the CAISO TPP LCR analysis/graphs are applicable for system-only resource adequacy (RA). CPUC staff believes this is appropriate based on discussion with CAISO staff and Staff proposes to use the higher limit for system-only RA. Staff believes this is more likely to enable the mapping of a large amount of battery resources included in recent IRP portfolios. If in practice staff finds that this is more than necessary to map the portfolio, then the portfolio can be trimmed down accordingly. CalCCA agrees and supports staff's proposal, rather than the alternative proposal to consider the (lower) charging limit for 4-hour batteries for local plus system RA to be the binding constraint.

II. CONCLUSION

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

Respectfully submitted,

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General Counsel to the
California Community Choice Association

November 10, 2020

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	R.19-11-009

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION ON TRACK 3.A ISSUES: LOCAL CAPACITY REQUIREMENT REDUCTION COMPENSATION MECHANISM AND COMPETITIVE NEUTRALITY RULES

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SUMMARY OF RECOMMENDATIONS

CalCCA requests that the Commission modify the PD as follows:

1. Expand eligibility for the local capacity requirement reduction compensation mechanism (LCR RCM) to include all preferred and energy storage resources to encourage not only the development of new resources but re-contracting of existing preferred and energy storage resources by load-serving entities (LSEs).
2. At a minimum, expand LCR RCM eligibility to include (a) all new preferred and energy storage resources not included in the baseline resources underlying Decision (D.) 19-11-016 and (b) new contracts for procurement of existing preferred resources executed on or after November 13, 2019, to ensure that LSEs executing contracts before D.20-06-002 to meet their procurement track requirements are not penalized for early action.
3. Ensure that an investor-owned utility's showing of local resource adequacy (RA) from the Power Charge Indifference Adjustment (PCIA) portfolio results in a financial credit to the PCIA rate, whether through valuation at the market price benchmark or by imputing the LCR RCM value to the local RA. This change will prevent what would otherwise be a cost shift from pre-2009 Direct Access (DA) customers to investor-owned utility bundled customers and Community Choice aggregation (CCA) customers.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	R.19-11-009

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING COMMENTS ON THE PROPOSED DECISION ON TRACK 3.A ISSUES: LOCAL CAPACITY REQUIREMENT REDUCTION COMPENSATION MECHANISM AND COMPETITIVE NEUTRALITY RULES

The California Community Choice Association (CalCCA)[1] submit these comments pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure on the October 23, 2020 proposed *Decision On Track 3.A Issues: Local Capacity Requirement Reduction Compensation Mechanism And Competitive Neutrality Rules* (PD).

I. INTRODUCTION

CalCCA appreciates the PD's adoption of CalCCA's "Option 2" local capacity requirement reduction mechanism (LCR RCM) with limited modifications. In this respect, the PD reasonably balances CCAs' interests in maintaining an economic incentive to locate new resources in local reliability areas with the goal of preventing "leaning" by one load-serving

1 California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, CleanPowerSF, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, 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, Silicon Valley Clean Energy, Solana Energy Alliance, Sonoma Clean Power, Valley Clean Energy, and Western Community Energy.

entity (LSE) on the procurement of other LSEs. CalCCA's comments thus are limited to two areas of concern.

First, the PD inadvertently penalizes early actors by limiting LCR RCM eligibility to preferred or energy storage resources contracted on or after June 17, 2020 (date of D.20-06-002 issuance). CalCCA proposes an expansion of eligibility to include all non-large hydro preferred or energy storage resources regardless of their contract execution date. Broadening the eligibility will provide a financial incentive to load-serving entities not only to make new investments in such resources but to recontract with existing preferred and energy storage resources. Removing large hydro resources from the mix should address the concern regarding the number of resources that would be eligible for the LCR RCM. At a minimum, however, the Commission should expand eligibility to include (a) all preferred and energy storage resources that are "incremental" to the D.19-11-016 baseline, and (b) contracts for the procurement of existing preferred and energy storage resources executed on or after November 13, 2019.

Second, without clarification, the PD may shift costs among customers contrary to Public Utilities Code §365.2 by permitting investor-owned utilities (IOUs) to show their local resources in their PCIA to the Central Procurement Entity (CPE) without compensation. This conveys the value of these PCIA resources to all customers while only a subset of customers is required to pay for them. CalCCA thus proposes clarifying how PCIA-paying customers will be compensated for conveying the value of the resources they pay for to other customers.

Finally, these comments also address the competitive neutrality rules adopted by the PD. CalCCA continues to maintain that designating the IOUs as CPEs, regardless of rules governing their conduct, prevents competitive neutrality. The retail electricity market has evolved too far to continue to place the IOUs in any procurement-related central role.

II. THE PD'S LIMITS ON LCR RCM ELIGIBILITY INADVERTENTLY PENALIZES EARLY ACTORS AND REMOVES INCENTIVES FOR RE-CONTRACTING EXISTING PREFERRED RESOURCES

The PD adopts a methodology to provide financial compensation to LSEs who contract for new preferred resources in local reliability areas. The PD defines "new" as "[a]ny new preferred resource or energy storage resource with a contract executed on or after June 17, 2020." This eligibility threshold ignores important *new* resources contracted before June 17, 2020 and penalizes early actors who contracted for new local resources before D.20-06-002 was issued. The threshold also eliminates financial incentives for LSEs to contract with *existing* preferred and energy storage resources. By precluding eligibility under the LCR RCM, the PD discourages LSEs from procuring or contracting these resources for any reason, unless they are willing to give up *all* RA attributes associated with the resource in the CPE solicitation – a risky move in a market where system RA is scarce. For this reason, the Commission should modify the PD to expand eligibility for LCR RCM compensation.

A. Expand Eligibility to Include All Non-Large Hydro Preferred and Energy Storage Resources

CalCCA proposed to permit LCR RCM participation by *all* preferred and storage resources contracted by LSEs.[2] This scope would ensure that LSEs not only have a financial incentive to develop new resources in local areas but would provide the same incentives for LSEs to contract with existing preferred resources. The PD rejects this proposal, raising concern that this scope of eligibility would make 7,100 MW in August (36 percent of the total 2021 local requirement) eligible for the LCR RCM compensation, risking unintended consequences.[3]

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2 *See* PD at 18.
3 *Id.* at 19.

As a preliminary issue, the calculation methodology underlying the estimated 7,100 MW lacks clarity. The PD's list of fuel types for preferred resources in footnote 49[4] incorrectly excludes geothermal resources. In addition, the list includes "water", suggesting that *all* hydro resources have been included in this total, including large hydro. CalCCA recommends the analysis the PD relies on for existing preferred resources should include geothermal and exclude large hydro. Removing large hydro from the analysis will likely significantly reduce the amount of existing preferred resources eligible for LCR RCM. Finally, preferred resource eligibility is further limited by the requirement that the LSE offer a minimum term of three years for its commitment to the CPE.

CalCCA acknowledges the PD's concern regarding the potentially "large volume" of resources that would be eligible if all preferred resources are included. Thus, as discussed above CalCCA proposes further refinement of the original proposal to exclude large hydro facilities from eligibility for the LCR RCM. This refinement mitigates the PD's concern and maintains a financial incentive to continue re-contracting with existing preferred resources.

B. In the Alternative, Expand Eligibility to Include All Preferred and Energy Storage Resources Not Included in the D.19-11-016 Baseline and Contracts for Existing Preferred and Energy Storage Resources Executed on or After November 13, 2019

If the Commission elects not to expand eligibility to include all non-large hydro, preferred and energy storage resources, it should consider a more narrowly tailored expansion. As the Commission explored the need for new resources in its Integrated Resources Planning (IRP) proceeding, some LSEs began soliciting and contracting new resources. The Commission should modify the PD to recognize the important early action these LSEs took to invest in new preferred and energy storage resources to address growing local constraints. To avoid penalizing

[4] PD at 18.

this early action, the LCR RCM eligibility should be expanded to include new local preferred and energy storage resources that are incremental to the D.19-11-016 baseline resource list, even if they were contracted before June 17, 2020. In addition, to encourage future re-contracting of needed existing preferred resources, the Commission should expand eligibility to include new contracts for existing resources executed on or after November 13, 2019.

D.19-11-016 mandated the procurement of 3,300 MW of new system RA resources to be placed into operation from 2021-2024. The road to this mandate began with a November 16, 2018, ruling in Rulemaking (R.)16-02-007 seeking comments on reliability, which led to the initiation of a "procurement track" in D.19-04-040.[5] The Commission initiated the procurement track in a ruling on June 20, 2019, proposing procurement of an additional 2,000 MW of new peak capacity statewide, extension of certain retirement dates for once-through-cooling generation, and procurement of an additional 500 MW in the Southern California Edison Company (SCE) service territory.[6] Following comments on this ruling, the Commission issued D.19-11-016 on November 13, 2019, ordering proportional procurement by all LSEs of 3,300 MW of "new" resources statewide. New resources were defined against a "set of baseline resources used to develop the PSP adopted in D.19-04-040, with certain adjustments."[7]

Following the issuance of the proposed *Decision Requiring Electric System Reliability Procurement for 2021-2023*, Clean Power Alliance (CPA) issued a request for offers (RFO) for new local resources on October 14, 2019.[8] CPA sought stand-alone energy storage projects with commercial operation dates (CODs) no later than August 1, 2023, with priority fast-track status

5 *See* D.19-11-016 at 4; *see also* D.19-04-040, Conclusions of Law 19-23 at 174-175.

6 *Assigned Commissioner and Administrative Law Judge's Ruling Initiating Procurement Track and Seeking Comment on Potential Reliability Issues*, June 20, 2019, at 14-16.

7 D.19-11-016, Finding of Fact 18 at 70.

8 https://cleanpoweralliance.org/2019-reliability-rfo.

to projects with CODs on or before August 1, 2021.[9] As a result of the request, CPA contracted its Luna Storage 100 MW standalone battery storage project on April 9, 2020, prior to the issuance of D.20-06-002. The project was ranked "high" in the RFO results due, in part, to its location in SCE's Big Creek/Ventura local reliability area.[10] If the PD is adopted without modification, this project, executed in response to the Commission's procurement track mandate, would be excluded from obtaining an LCR RCM credit for its local value.

Similarly, the PD would exclude from LCR RCM compensation the local RA from the innovative Oakland Clean Energy Initiative projects, developed jointly by East Bay Community Energy (EBCE) and Pacific Gas and Electric Company (PG&E) to solve local reliability needs. EBCE and PG&E first issued a request for offers (RFO) for the projects in early 2018. The RFO resulted in the selection of a 7 MW energy storage project to be developed by esVolta and a 36.25 MW/145 MWh energy storage system to be developed by Vistra Energy on the site of the existing Oakland Power Plant (currently designated as a Reliability Must Run facility by the California Independent System Operator).[11] EBCE's Board of Directors approved an RA contract with Vistra on June 5, 2019, and an RA contract with esVolta on July 17, 2019, following D.19-04-014 and in the midst of the Commission's procurement track deliberations. In 2020, EBCE amended its contract with Vistra to add additional capacity to the project. Like CPA, EBCE believed that in executing the Vistra and esVolta agreements and amendment[12]

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9 https://www.ascendanalytics.com/cpa-storage-rfo.

10 https://cleanpoweralliance.org/wp-content/uploads/2020/03/040220-CPA-Board-Agenda-Packet.pdf, Memorandum to CPA Board of Directors from Natasha Keeper, Director of Power Planning & Procurement, at 22 ("The project ranks High as it is located within Los Angeles County. Additionally, it will provide new resources for the capacity constrained Big Creek-Ventura local area.")

11 https://cal-cca.org/east-bay-community-energy-approves-ra-contract-with-vistra-energy-for-new-battery-energy-storage-project-paving-way-for-shut-down-of-fossil-fuel-fired-power-plant-in-oakland/.

12 https://res.cloudinary.com/diactiwk7/image/upload/ebce_retreat_packet_6_5_19-1.pdf, Item 6, Background.

would provide local RA value to EBCE and its customers. And like CPA's Luna project, the PD would preclude EBCE's Oakland Clean Energy Initiative RA procurement from accessing an LCR RCM credit.

These three resources present sound examples of early action by LSEs to procure resources where they are needed most before the Commission's adoption of D.20-06-002. Importantly, both resources are incremental to the baseline underlying D.19-11-016. To ensure that all such resources may obtain local value *without* requiring the LSE to sacrifice valuable system and flexible RA and other attributes, the Commission should expand eligibility LCR RCM eligibility. At a minimum, eligibility should include all preferred and energy storage resources incremental to the D.19-11-016 baseline.

III. ALLOWING AN IOU TO SHOW LOCAL PCIA-ELIGIBLE RESOURCES TO THE CPE FOR NO COMPENSATION DIRECTLY SHIFTS COSTS FROM PRE-2009 DIRECT ACCESS CUSTOMERS TO BUNDLED AND CCA CUSTOMERS

The PD responds to CalCCA's concerns regarding the potential cost shifts arising from an IOU's offering of PCIA-eligible local resources to the CPE for no compensation.[13] The PD affirms that IOUs may show their local resources to the CPE for no compensation and retain their system and flexible RA attributes.[14] It reasons that since other LSEs may show their resources to the CPE for no compensation, the IOUs should have the same rights. The problem, however, is not whether the IOUs may show the resource for no compensation, but how the showing of local RA from a PCIA-eligible resource is accounted for and credited back to the PCIA. CalCCA requests that the Commission modify the PD to clarify the nature of the compensation or credit that will be provided against the PCIA portfolio if such a resource is shown to the CPE for no compensation.

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13 PD at 16-17.
14 PD at 17.

CalCCA throughout the CPE debate has raised the concern that allowing an IOU to show PCIA resources for no compensation would shift costs from pre-2009 DA customers to bundled and departing load customers.[15] While pre-2009 DA customers do not pay the costs of many (if not most) of these resources, they would receive the financial benefit of the resources' local RA attributes provided for free to the CPE at the expense of PCIA-paying customers. The PD dismisses this concern, however, suggesting that compensation to the PCIA will be provided. Quoting D.20-06-002, the PD explains that "'shown resources are still subject to the local PCIA benchmarks adopted in D.19-10-001, which provide an RA capacity offset to the PCIA charge.'"[16]

If the above-referenced conclusion were true, CalCCA would have no concern. It is *not* clear, however, that the local RA attributes shown to the CPE would be valued at the local RA benchmark. First, with the introduction of the CPE, the development and use of the local RA benchmark requires examination, which should occur in R.17-06-026 or its successor proceeding. Even assuming the benchmark continues to apply as it is currently formulated, there is nothing in existing decisions that requires the benchmark to be applied to local RA shown to the CPE for no compensation. Today, the benchmark is applied for *forecast* purposes in PCIA calculations to all resources except those deemed "unsold."[17] Nowhere, however, has the Commission stated that the resources would be treated as "sold" despite the lack of compensation. In addition, this analysis fails to consider the true-up of the forecast benchmark to *actual* revenues; the true-up adjusts the forecast so that the benchmark is applied *only* to

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15 *California Community Choice Associations Comments on Track 3.A. Working Group Report,* Sept.11, 2020, at 9-10; *see also California Community Choice Association Reply Comments on Proposed Decision on Central Procurement of the Resource Adequacy Program,* R.17-09-020, April 20, 2020, at 2.

16 PD at 17 (*quoting* D.20-06-002 at 77).

17 D.19-10-001, Ordering Paragraph 3.e.

resource attributes used on behalf of bundled customers. Thus, unless the Commission is suggesting that 100 percent of the resources shown to the CPE for no compensation are attributed to bundled customers, and priced in the true-up calculation at the market price benchmark, it is not clear that the benchmark would apply. And if the benchmark does not apply in the true-up, the "actual" revenues from sale would be credited against the final PCIA calculation. If shown to the CPE for no compensation, the sales revenues and thus the PCIA credit would be zero.

In short, the PD errs in incorporating the language of D.20-06-002 in addressing CalCCA's concern. The Commission should thus modify the final decision, stating that PCIA costs will be credited for any PCIA-eligible resources shown by the IOU for no compensation, deferring the methodology for further consideration. It should further direct a working group to determine whether the credit would be applied through a MPB for local RA or, for example, by requiring the CPE to pay the PCIA portfolio the LCR RCM predetermined price for the resource.

IV. BY DEFINITION, PLACING AN IOU IN THE ROLE OF CPE PRECLUDES COMPETITIVE NEUTRALITY

The PD adopts the "competitive neutrality" rules proposed by the IOUs to mitigate the risk of intra-utility sharing of sensitive market information. It quotes D.20-06-002, stating: "'The Commission recognizes that this competitive information should be appropriately protected in an effort to address anti-competitive concerns and facilitate confidence and certainty in the central procurement process.'"[18] While CalCCA appreciates the Commission's intention and objectives, CalCCA continues to oppose placing IOUs in the role of CPEs. Placing LSEs in this role undeniably create the risk of inappropriate information sharing within the CPE and procurement organizations within the IOU; indeed, that risk is precisely what the rules attempt to

[18] PD at 26 (*quoting* D.20-06-022 at 64).

address. In a retail market with more than 40 active LSEs, however, central procurement by the incumbent IOU no longer makes sense and will not "facilitate confidence and certainty in the central procurement process." While CalCCA proposes no changes to the rules within the context of the current CPE, CalCCA urges the Commission to move quickly toward a more competitively neutral alternative.

V. CONCLUSION

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

Respectfully submitted,

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November 12, 2020

APPENDIX A

Proposed Changes to Conclusions of Law and Ordering Paragraphs

Conclusions of Law

Proposal A:

2. CalCCA's Option 2 proposal should be adopted, with modifications, to apply ~~only~~ to ~~new~~ all preferred resources ~~or~~ and energy storage resources excluding large hydro resources.

Proposal B:

2. CalCCA's Option 2 proposal should be adopted, with modifications, to apply ~~only~~ to new preferred resources or energy storage resources not included in the D.19-11-016 baseline resources and to new contracts for existing preferred resources executed on or after November 13, 2019.

Conclusions of Law

Proposal A:

4. Any ~~new~~ preferred resource or energy storage resource, excluding large hydro resources, ~~with a contract executed on or after June 17, 2020~~ shall be eligible for the local capacity requirement reduction compensation mechanism.

Proposal B:

4. Any new preferred resource or energy storage resource not included in the D.19-11-016 baseline and any new contract with an existing preferred resource executed on or after November 13, 2019, ~~with a contract executed on or after June 17, 2020~~ shall be eligible for the local capacity requirement reduction compensation mechanism.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Microgrids Pursuant to Senate Bill 1339.	Rulemaking 19-09-009 (Filed September 12, 2019)

REPLY COMMENTS OF CALIFORNIA CHOICE ENERGY AUTHORITY, THE CITY OF SAN DIEGO, THE CITY OF SAN JOSÉ (SAN JOSÉ CLEAN ENERGY), CLEAN POWER ALLIANCE, EAST BAY COMMUNITY ENERGY, LANCASTER CHOICE ENERGY, MARIN CLEAN ENERGY, MONTEREY BAY COMMUNITY POWER AUTHORITY, PENINSULA CLEAN ENERGY AUTHORITY, PIONEER COMMUNITY ENERGY, REDWOOD COAST ENERGY AUTHORITY, SILICON VALLEY CLEAN ENERGY, SOLANA ENERGY ALLIANCE, AND SONOMA CLEAN POWER AUTHORITY ON THE ORDER INSTITUTING RULEMAKING

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NOVEMBER 5, 2019

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

Order Instituting Rulemaking Regarding Microgrids Pursuant to Senate Bill 1339.	Rulemaking 19-09-009 (Filed September 12, 2019)

REPLY COMMENTS OF CALIFORNIA CHOICE ENERGY AUTHORITY, THE CITY OF SAN DIEGO, THE CITY OF SAN JOSÉ (SAN JOSÉ CLEAN ENERGY), CLEAN POWER ALLIANCE, EAST BAY COMMUNITY ENERGY, LANCASTER CHOICE ENERGY, MARIN CLEAN ENERGY, MONTEREY BAY COMMUNITY POWER AUTHORITY, PENINSULA CLEAN ENERGY AUTHORITY, PIONEER COMMUNITY ENERGY, REDWOOD COAST ENERGY AUTHORITY, SILICON VALLEY CLEAN ENERGY, SOLANA ENERGY ALLIANCE, AND SONOMA CLEAN POWER AUTHORITY ON THE ORDER INSTITUTING RULEMAKING

Pursuant to the Order Instituting Rulemaking Regarding Microgrids Pursuant to Senate Bill 1339, dated September 19, 2019 (the "OIR"), California Choice Energy Authority, the City of San Diego, the City of San José (San José Clean Energy), Clean Power Alliance, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Monterey Bay Community Power Authority, Peninsula Clean Energy Authority, Pioneer Community Energy, Redwood Coast Energy Authority, Silicon Valley Clean Energy, Solana Energy Alliance, and Sonoma Clean Power Authority (collectively, the "Joint CCAs") respectfully submit this reply to opening comments that parties filed in this proceeding on October 21, 2019. The Joint CCAs are Community Choice Aggregators ("CCAs") that serve customers in various communities throughout California.[1] The City of San Diego and Solana Energy Alliance submitted separate opening comments but join with the Joint CCAs in this reply.

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[1] California Choice Energy Authority, the City of San Diego, the City of San José (San José Clean Energy), Clean Power Alliance, East Bay Community Energy, Lancaster Choice Energy,

I. SUMMARY OF JOINT CCA REPLY COMMENTS

Opening comments identify a number of microgrid projects that CCAs are currently facilitating across the state. For example, Lancaster Choice Energy ("LCE") is currently deploying microgrids for two zero-net energy, low-cost housing developments that are part of LCE's Electric Program Investment Charge ("EPIC") grant for Advanced Energy Community Design.[2] Monterey Bay Community Power ("MBCP") is developing a microgrid program with two focus areas: first, a community resilience program focused on supporting community preparedness for critical facilities located in areas facing Public Safety Power Shut Off ("PSPS") events; and second, MBCP will work with existing commercial customers to establish microgrids to meet the energy needs of businesses with prolonged interconnection delays.[3] Peninsula Clean Energy ("PCE"), along with East Bay Community Energy ("EBCE"), has received a grant from the Bay Area Air Quality Management District to identify critical facilities in San Mateo and Alameda Counties that serve as community shelters and/or emergency response hubs during disasters (e.g., police and fire departments, recreation centers, libraries, etc.) and assess such locations for deployment of microgrids and resiliency projects.[4] Redwood Coast Energy Authority ("RCEA") is working with Pacific Gas & Electric Company ("PG&E") and Schatz Energy Research Center to install the first front-of-the-meter, multi-customer microgrid in PG&E's service territory, which will support 18 customers, including the Humboldt

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Marin Clean Energy, Monterey Bay Community Power Authority, Pioneer Community Energy, Redwood Coast Energy Authority, Silicon Valley Clean Energy, Solana Energy Alliance, and Sonoma Clean Power Authority have given counsel for Peninsula Clean Energy Authority permission to sign this pleading on their behalf.

[2] Joint CCA at 4.

[3] Joint CCA at 8.

[4] Joint CCA at 9.

County Airport and the U.S. Coast Guard Air Station.[5] Lastly, the Port of Long Beach ("Long Beach"), although not a CCA, is developing a microgrid that will be installed at the Port's Joint Command and Control Center, which houses the Port's Security Division and Harbor Patrol, as well as units from the Long Beach Police Department.[6] The Joint CCAs see the IOUs and industry as key partners in our efforts, and we look forward to learning from the Port of Long Beach and other parties regarding the solutions they have deployed in moving microgrid projects forward in California.

Party opening comments identify a comprehensive list of salient issues to resolve if impediments to microgrid commercialization are to be fully removed. Below, the Joint CCAs propose a path for resolving the many important issues raised in opening comments, while also satisfying SB 1339's objective to: "facilitate commercialization of microgrids for distribution customers of large electrical corporations."[7] Specifically, the Joint CCAs recommend that the Commission adopt three, broad "use cases" and focus this docket initially on clearing paths for two of these: (1) single-customer microgrids, which we refer to in this reply as "behind-the-meter" ("BTM") microgrids, and (2) community-scale microgrids that involve a load-serving entity ("LSE") in the retail sales role and are focused on resilience. A third use case, community-scale microgrids with a non-LSE in the retail sales role, should be addressed in this proceeding but party opening comments raise a number of legal issues with this use case that may take more time to resolve.

Opening comments also identify a need to move quickly to enable increased use of microgrids in California prior to the next fire season. Simply put, events have overtaken SB

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[5] RCEA at 1.
[6] Long Beach at 4-5.
[7] Public Util. Code § 8371.

1339's proposed timeframe of December 1, 2020 to remove impediments to microgrid commercialization. Bloom Energy Corporation ("Bloom"), California Hydrogen Business Council ("CHBC"), and Schneider Electric North America ("Schneider") highlight the urgency of moving quickly.[8] CHBC states: "As planned power shutdowns interrupt daily life and business for hundreds of thousands of ratepayers – and pocketbooks, health, and even life for the most vulnerable – it is imperative that California accelerate action on implementing microgrids."[9] These parties propose to expedite tariff and rule development for BTM microgrids to March 2020 to facilitate implementation before the next fire season.[10] The Joint CCAs agree that the Commission should prioritize and resolve BTM microgrid issues by March 2020, as we explain below. We also propose that the Commission prioritize and resolve community-scale microgrids that involve an LSE in the retail sales role and are focused on resilience by April 2020.

II. PROPOSED PATH FORWARD, BASED ON OPENING COMMENTS

Below, we propose a path forward to resolve the many important issues raised in opening comments, while also satisfying SB 1339's microgrid commercialization objectives. The Joint CCAs provide these proposals in order of priority, beginning with the most important.

1. The Commission should identify three specific microgrid "use cases".

Numerous parties state that identifying broad categories of microgrid, or "use cases", is a logical starting point for this proceeding.[11] For example, PG&E proposes three: (1) single

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[8] Bloom at 7-9; CHBC at 6-7; Schneider at 3.
[9] CHBC at 6.
[10] Bloom at 7-9; CHBC at 6-7; Schneider at 3.
[11] *See*, *e.g.*, Bloom at 2; California Clean Energy Committee ("CCEC") at 2; PG&E at 2-7; Small Business Utility Advocates ("SBUA") at 4; San Diego Gas & Electric Company ("SDG&E") at 4; SCE at 5.

customer microgrids, (2) multiple-customer microgrids addressing community-level objectives, and (3) multiple-customer microgrids addressing broader wildfire risk reduction and system cost reduction opportunities.[12] PG&E proposes that only the first two use cases should be addressed in this proceeding and that the third category be considered out of scope.[13] By comparison, the UC Davis Policy Institute for Energy ("UCDPI") combines the second and third of PG&E's use cases together under the single umbrella, "advanced microgrids", which contain multiple customers and multiple resources that may be interconnected on both sides of the utility customer billing meter.[14] Clean Coalition ("CC") similarly refers to the second and third of PG&E's use cases broadly as "community microgrids", whereas Green Power Institute ("GPI") refers to them as "multi-user microgrids".[15]

The Joint CCAs propose that the Commission adopt three use cases: (1) "BTM" microgrids, (2) community-scale microgrids that involve an LSE in the retail sales role and that are focused on resilience, and (3) other types of community-scale microgrids that would involve a non-LSE in the retail sales role. The Joint CCAs support PG&E's distinction between two different types of multiple-customer microgrids – referred to herein by the Joint CCAs as community-scale microgrids – as we believe this distinction will be helpful in addressing cost-benefit analysis and may be useful in developing tariffs to support the deployment of microgrids. Moreover, as noted below, the Joint CCAs believe the focus of this docket during the early stages should be on clearing paths for "BTM" microgrids and community-scale microgrids that involve an LSE in the retail sales role and are focused on resilience. However, we disagree with

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[12] PG&E at 2-7.
[13] PG&E at 6.
[14] UCDPI at 3.
[15] CC at 3; GPI at 4.

PG&E that any type of microgrid should be excluded from this docket. All entities interested and capable of deploying microgrids, including CCAs, should be allowed to do so, and SB 1339 makes no distinction between types of microgrid for distribution customers of large electrical corporations that the Commission should aim to facilitate.

Importantly, the Joint CCAs believe that categorizing microgrids into three specific use cases, as we propose, will help prioritize issues to address first in this proceeding. Identifying use cases will also help identify roles and responsibilities, which may differ by use case, as Southern California Edison ("SCE") explains:

> "The configurations of microgrids, the roles and responsibilities associated with development and ownership of microgrids, operational protocols, and the rate structures that support appropriate cost allocation and recovery should all be guided by the specific agreed upon use cases. In considering each use case, the Commission should also address factors such as reliable control, safe operation, cybersecurity requirements, communication and monitoring, power quality, and interoperability with the broader utility network in developing microgrid operating frameworks. This will help to ensure that customers receive safe, resilient, reliable, clean and affordable microgrid services."[16]

The Joint CCAs agree.

2. The Commission should resolve BTM microgrid issues by March 2020.

In general, the roles and responsibilities of BTM installations are already generally well defined. Existing statutes, regulations, tariffs, and past Commission decisions all clearly allow for non-utility ownership of BTM generators and storage devices and allow non-LSEs to make power sales to onsite customers (and certain nearby customers[17]) without violating utility exclusive service territories or subjecting the service provider to public utility regulation. As PG&E observes, "[m]any campuses, military bases, hospitals, and industrial customers have used microgrid configurations successfully for decades to manage loads and resources and

[16] SCE at 5.
[17] *See* Pub. Util. Code § 218(b).

provide back-up power in the event of a grid outage."[18] In addition, PG&E notes "impact studies necessary for interconnection of single-customer microgrids, and to study the related impacts to the electric grid, are already well developed."[19]

There are, however, issues that remain to be resolved if BTM microgrids are to be fully commercialized in California. In particular, parties' opening comments identify several important issues to resolve, including:

- Improve <u>Rule 21</u> to facilitate prompt and economic interconnections with microgrids.[20]
- Modify <u>Rule 18</u> to permit microgrids with both generating resources and energy storage to re-sell electricity from storage without tracing whether the electrons in storage were delivered by the interconnected utility or were generated by onsite generation.[21]
- Reevaluate "cost-of-ownership" charges in <u>Rule 2</u>.[22]
- Consider applicability of "exit fees" to microgrid customers.[23]

This may not be a complete list of BTM microgrid issues that need to be resolved, but this list offers a good starting point based on party opening comments. To further identify relevant issues, the Joint CCAs encourage the Commission to issue a request for comment in the near future specifically asking that parties identify the unique subset of issues that need to be

[18] PG&E at 2.
[19] PG&E at 9.
[20] California Solar and Storage Association ("CalSSA") at 6; California Energy Storage Alliance ("CESA") at 3-4; Enel X North America (Enel") at 4-5; GPI at 1; Long Beach at 6; Microgrid Resource Coalition ("MRC") at 5-6; SEA/San Diego at 3-4; Shell Energy North America ("Shell") at 5.
[21] Long Beach at 6
[22] CalSSA at 6.
[23] *See*, *e.g.*, MRC at 4-5.

resolved to fully remove impediments to commercializing BTM microgrids. The Joint CCAs believe BTM use cases likely represent the "low hanging fruit" of commercializing microgrids and removing existing impediments to their commercialization will help empower many Californians to take actions that increase their personal safety and energy resilience before the next fire season.

The Joint CCAs also agree with parties that propose to address such issues early in 2020. To do so, the Joint CCAs agree with parties that propose to work with existing tariffs and rules where possible and to modify those tariffs and rules as necessary.[24] The Joint CCAs also agree that some issues may be more suitable for resolution in other venues.[25] For example, SCE notes that the Commission is already developing a standard for direct current metering in the Rule 21 OIR (R.17-07-007).[26]

3. The Commission should resolve impediments to community-scale microgrids that involve an LSE in the retail sales role and are focused on resilience by April of 2020.

RCEA identifies microgrid use cases that focus on improving resiliency in communities that rely on high-risk transmission or distribution lines for power and that target critical facilities and infrastructure, vulnerable communities and neighborhoods, disadvantaged communities, and communities with high populations of medical baseline customers.[27]

The Joint CCAs believe community-scale microgrids that involve an LSE in the retail sales role and that focus on resilience can be facilitated before next fire season and should be prioritized in this proceeding. PG&E's opening comments appear to agree that such microgrids

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[24] National Fuel Cell Research Center ("NFCRC") at 7-8; SCE at 3-4.
[25] *See* SCE at 4; SDG&E at 5.
[26] SCE at 4. *See also* CESA at 4; GPI at 5-6; PG&E at 10-11.
[27] RCEA at 5-7.

should be prioritized.[28] The CCA microgrid projects discussed herein highlight the important role that CCAs can undertake in facilitating these projects, which dovetail with the community focus of California's CCAs. Simply put, we are highly motivated to facilitate these use cases. For example, PCE's Board of Directors recently committed up to $10 million over three years to fund clean backup power for San Mateo's medically vulnerable residents and essential community services during PG&E power shutoffs.[29] In addition, the CEC has issued numerous EPIC grants to help facilitate resiliency-focused projects, meaning that project economics are not a barrier to many such projects moving forward. Importantly, as demonstrated by the RCEA/PG&E microgrid example, these use cases can also proceed without resolving legal considerations that a third category of community microgrid use case raises, which we discuss below.

Issues that must to be resolved to facilitate community-scale microgrids that involve an LSE in the retail sales role and are focused on resilience have been highlighted in opening comments, specifically:

- Develop contracts and tariffs that address the financial and operational roles and responsibilities of customers, load-serving entities, and the transmission/distribution operator associated with a multi-user microgrid.
- Determine how to best allocate the incremental costs and benefits associated with the hardware and software needed to enable occasional stand-alone operation for a line segment serving multiple customers.[30]

[28] PG&E at 5.
[29] *See* http://bit.ly/347dEXB.
[30] PG&E at 5.

- Improve coordination and information-sharing related to overall distribution grid planning between microgrid developers/owners, customers interested in microgrid participation, LSEs interested in facilitating microgrids, and distribution utilities.

Similar to interconnection studies and related requirements for information sharing during the interconnection process, this coordination and information-sharing should be subject to maximum response times to ensure microgrids can proceed with development in a timely fashion.

Additional issues may also need to be identified. The Joint CCAs propose that the Commission convene a workshop in the first quarter of 2020 so that parties may share solutions and identify additional issues that may need to be resolved to facilitate community-scale microgrids that involve an LSE in the sales role and are focused on resilience. The Joint CCAs agree with Solana Energy Alliance and the City of San Diego ("SEA/San Diego") as well as other parties that convening a workshop that focuses on existing microgrid projects will allow the Commission and parties to learn and benefit from these experiences.[31]

The Joint CCAs also encourage RCEA, PG&E and others with knowledge of tariff/contract solutions to broadly share that knowledge so that others can learn from their experiences. For example, PG&E is working with RCEA and several community stakeholders in the Humboldt area to develop a microgrid that will support 18 customers, including the Humboldt County Airport and the U.S. Coast Guard Air Station.[32] PG&E explains that this microgrid will be a "first-of-its-kind multi-user microgrid powered by 100 percent renewable

[31] SEA/San Diego at 4-5. See also PAO at 11-13; Southern California Gas Company ("SoCal Gas") at 6.
[32] PG&E at 5.

energy."[33] In connection with this project, RCEA explains that PG&E, RCEA and the Schatz Energy Research Center have been working to develop thee separate experimental tariffs to guide the flow of revenue between the customer, the utility and the microgrid owner for this project.[34] PG&E states that this project will "serve as a test bed to develop policies, tariff structures, and opening procedures necessary to integrate multiple-customer microgrids into California's electric grid."[35]

The Joint CCAs look forward to learning from this and other projects that can help establish a path forward for further commercializing community-scale microgrids that involve an LSE in the power sales role and are focused on resilience. The Joint CCAs encourage the Commission to complete its review of this use case of microgrid projects by April of 2020 so these projects may move forward to completion in advance of the next fire season, assisted in many cases with EPIC and community funding.

4. A broader category of community microgrid use case, which involves a non-LSE in the power sales role, raises legal issues that may take more time to resolve.

This broader class of community microgrids includes those in which a non-LSE would sell power to multiple customers from generation and storage sources that are not strictly BTM. Numerous parties identify the "over the fence rule" as a significant impediment to commercializing this use case of microgrids.[36] The "over the fence rule" in Public Utilities Code Sec. 218(b) currently restricts the geographic scope and number of customers that may be sold power from distributed generation. As such, this "rule" limits the ability of non-LSEs to sell

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[33] PG&E at 5.
[34] RCEA at 4-5.
[35] PG&E at 5.
[36] CalSSA at 5; Center for Sustainable Energy ("CSE") at 4-5; GPI at 4.; Tesla, Inc. ("Tesla") at 3-4.

power from local generation broadly within a microgrid. Resolution of this issue may require statutory changes.

Numerous parties also identify public utility regulation[37] and LSE exclusive service areas[38] as additional impediments to commercializing community microgrids in which a non-LSE would sell power broadly to microgrid customers. The Joint CCAs acknowledge that these legal considerations may presently restrict certain outcomes with respect to the roles and responsibilities in this broader category of community microgrid, specifically the ability of non-LSEs to sell power from local generation broadly within a microgrid. However, resolution of these legal considerations will require a careful balancing of the desire to commercialize microgrids with the need to protect customers from discriminatory, unjust, and unreasonable charges. A full resolution of these issues may also require statutory changes outside of the Commission's control. Although these issues are worthy of further discussion in this proceeding, the Joint CCAs encourage the Commission to prioritize microgrid use cases that it is currently empowered to facilitate.

III. REPLY TO ADDITIONAL ISSUES RAISED IN OPENING COMMENTS

- **The Joint CCAs agree with PG&E that public and employee safety is paramount.[39]**

PG&E stresses the "first and most important goal of any policies, tariffs, or rules that might be adopted in this or other related proceedings is to ensure that microgrids do not diminish overall electric system safety."[40] The Joint CCAs agree, and we also believe that identifying roles and responsibilities for each use case will help clarify who is responsible for various

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[37] CalSSA at 4-5; CESA at 4-5; Coalition for California Utility Employees at 8; Shell at 6; Tesla at 3-4.
[38] CalSSA at 5; Shell at 5; Tesla at 3.
[39] PG&E at 7-8.
[40] PG&E at 7.

aspects of worker and public safety within each use case, as well as identifying responsibilities for maintaining reliable control, safe operation, cybersecurity requirements, communication and monitoring, power quality, and interoperability with the broader utility network.

- **The Joint CCAs agree that microgrid standards should be technology neutral.**

Most parties argue for a technology-neutral approach,[41] and several stress the importance of gas-fired generation as a component of microgrids, in particular for extending the time that a microgrid can operate while a utility system is down.[42] Several parties also propose to develop technology-neutral interoperability standards, such that the Commission's rules and tariffs would be generally agnostic regarding the types of generation and storage technologies employed in a microgrid.[43] The Joint CCAs agree with these comments and believe a technology neutral approach is consistent with SB 1339. The only prohibition the Joint CCAs observe in SB 1339 regarding technology neutrality is that certain types of generation cannot receive certain compensation.[44]

- **The Joint CCAs agree that microgrid ownership opportunities should be inclusive.**

Most parties argue for inclusiveness regarding acceptable business models.[45] Again, the Joint CCAs believe these proposals are consistent with SB 1339; however, we note that numerous parties identify several existing legal impediments that restrict non-LSEs from selling power broadly to customers within community-microgrids, as we discuss above.

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[41] Bloom at 9-12; California Clean DG Coalition at 2; CHBC at 3-4; CESA at 7; NFCRC at 4; MRC at 8; SoCal Gas at 4.
[42] MRC at 8; SoCal Gas at 5-6.
[43] CHBC at 4; Shell at 5.
[44] Pub. Util. Code § 8371(d).
[45] Bloom at 2; CESA at 7; Enel at 5; MRC at 6-7.

- **Quantifying a resiliency value is worthy of additional discussion but should not delay the Commission in quickly moving to facilitate (1) BTM microgrids, and (2) community-scale microgrids that involve an LSE in the retail sales role and are focused on resilience.**

Numerous parties propose that the Commission quantify a "resiliency value" in this proceeding.[46] Some of these parties propose that microgrid owners should be compensated for the resiliency value that their microgrids provide,[47] and that microgrid costs should be socialized if the Commission determines that benefits of microgrid projects accrue to non-microgrid customers.[48] On the other hand, the Public Advocate's Office ("PAO") argues that "the Commission should interpret the legislative prohibition on 'shifting costs between ratepayers' to include a prohibition against 'shifting costs between microgrid and non-microgrid customers.'"[49]

Implicit in these differing views are different perspectives on which customers benefit from a microgrid project, and whether improved resiliency and reduced PSPS events have spill over benefits to non-microgrid customers. The Commission will need to weigh these issues carefully with the understanding that microgrid costs and benefits may differ between use cases and even by specific applications within a use case. The Joint CCAs appreciate that these are difficult issues that may take time to address. Moreover, the Joint CCAs believe that the Commission and stakeholders must take a nuanced and careful view of the benefits of microgrids that are used for resilience. The provision of police, fire, medical and community services during an outage – planned or unplanned – is a core promise of microgrids and results in benefits that traditional cost-benefit analysis does not take into account.

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[46] CalSSA at 7; CC at 9-10.; CSE at 5-6; Enel at 7; Form at 4-5; Tesla at 6.
[47] CalSSA at 7-8; Form at 5; Tesla at 6.
[48] CalSSA at 6-7; CESA at 5-6; Tesla at 5.
[49] PAO at 1-2.

However, resolution of these issues should not delay the important steps that the Commission can immediately take to facilitate currently viable microgrid projects in two broad use cases prior to the next fire season: (1) BTM microgrids, and (2) community-scale microgrids that involve an LSE in the retail sales role and are focused on resilience. These two use cases do not raise the legal impediments that a third category of microgrid, with non-LSEs in a power sales role, currently raise, and, in many cases, are facilitated with EPIC and community funding and so do not require payments for "resiliency value" to be implemented before the next fire season.

I. CONCLUSION

The Joint CCAs look forward to working with the Commission and parties in this proceeding to craft a policy framework surrounding the commercialization of microgrids.

Respectfully submitted by:

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For California Choice Energy, the City of San Diego, the City of San José (San José Clean Energy), Clean Power Alliance, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Monterey Bay Community Power Authority, Peninsula Clean Energy Authority, Pioneer Community Energy, Redwood Coast Energy Authority, Silicon Valley Clean Energy, Solana Energy Alliance, and Sonoma Clean Power Authority

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	R.19-11-009

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
REPLY COMMENTS ON THE PROPOSED DECISION ON TRACK 3.A ISSUES:
LOCAL CAPACITY REQUIREMENT REDUCTION COMPENSATION MECHANISM
AND COMPETITIVE NEUTRALITY RULES

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November 17, 2020

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	R.19-11-009

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON THE PROPOSED DECISION ON TRACK 3.A ISSUES: LOCAL CAPACITY REQUIREMENT REDUCTION COMPENSATION MECHANISM AND COMPETITIVE NEUTRALITY RULES

The California Community Choice Association (CalCCA)[1] submit these reply comments pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure on the October 23, 2020 proposed *Decision On Track 3.A Issues: Local Capacity Requirement Reduction Compensation Mechanism And Competitive Neutrality Rules* (PD).

I. INTRODUCTION

CalCCA responds in these reply comments to Southern California Edison Company's (SCE's) opening comments on the PD. CalCCA supports SCE's proposal to correct the price calculation of the local capacity requirement reduction compensation mechanism (LCR RCM), by removing the inclusion of an effectiveness factor in determining the number of MW receiving compensation.[2] The Central Procurement Entity (CPE), as directed in D.20-06-002, will assess

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[1] California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, CleanPowerSF, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, 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, Silicon Valley Clean Energy, Solana Energy Alliance, Sonoma Clean Power, Valley Clean Energy, and Western Community Energy.

[2] *Southern California Edison Company's (U 338-E) Comments on Proposed Decision on Track 3.a. Issues* (SCE Comments) at 2-3.

effectiveness for shown resources in the same way it does for bid resources, taking effectiveness into account when selecting resources.[3] The CPE will not discount the number of MW offered by a bid resources based on the resource's effectiveness, and neither should it discount the MW shown by load-serving entities (LSEs).

II. THE COMMISSION SHOULD CORRECT THE CALCULATION OF THE PREDETERMINED LOCAL PREMIUM PRICE

SCE points out an important problem with the price formulation originally proposed by CalCCA and adopted by the PD. The PD, based on the Final Report,[4] describes the calculation as follows:

> • Year 1: Use the weighted average price from the last four quarters of Energy Division Power Charge Indifference Adjustment (PCIA) responses for both system and local RA; subtract system Resource Adequacy (RA) price from local RA price and *multiply by effective MW.*
>
> • Subsequent Years: Use the weighted average price from the last four quarters of Energy Division PCIA responses for system RA and the most recent weighted average price reported in the CPE solicitation results (prior year's results) for local RA price; subtract system RA price from local RA price and *multiply by effective MW.*[5]

This formulation, however, reflected the approach under discussion when the parties were continuing to discuss potential methodologies for evaluating effectiveness. Because parties were unsuccessful, and the CPE has the discretion in whether to take a shown resource, the discussion migrated to requiring the CPE to apply effectiveness considerations in *evaluating* the resource

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3 D.20-06-002, Ordering Paragraph 14 at 95.

4 *California Community Choice Association and Pacific Gas and Electric Company's (U 39 E) Track 3.A Working Group Report*, Sept. 1, 2020 (Final Report), Attachment 1-12.

5 PD, Ordering Paragraph 3, at 35.

rather than requiring incorporation in the payment calculation. Indeed, this approach is consistent with the Commission's directive in D.20-06-002.[6]

CalCCA's comments on the Final Report[7] clarified the calculation in one place, requiring the effectiveness determination to be made by the Central Procurement Entity (CPE) as it will for all bid resources:

Summary of CalCCA Option #2 Local Capacity Requirement Reduction Compensation Mechanism Recommendation	
CPE Obligation	The CPE may accept or reject the showing if more cost-effective resources are available.
Effectiveness	The CPE applies effectiveness criteria to shown resources in the same way the criteria are applied to bid resources.
Annual Price Update	If selected, the CPE will pay the LSE the showing price (pre-determined price or below) without annual adjustment for effectiveness, like bid resources.

Inadvertently, however, the original language requiring the price to be "multiplied by effective MW" remained in the same table.

SCE points out that requiring the CPE to consider effectiveness *and* discounting MW for effectiveness would lead to distortions.[8] The same calculation *would not* be applied to bid resources, thus distorting the relative values between resources. It could also lead to inflation of showing prices. SCE explains:

> While it is appropriate to consider resources' effectiveness in meeting a local area need, the effectiveness of a specific resource depends on the resource fleet being considered. Consideration of the effectiveness of resources shown under the LCR RCM is already addressed by requiring the CPE to apply the effectiveness criteria to shown resources in the same way such criteria are applied to bid resources. It is not appropriate to multiply the pre-determined local price by effective MW. It is not clear how effective MW would be calculated

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6 D.20-06-002, Ordering Paragraph 14 at 95 (requiring the CPE to consider local effectiveness in valuing and selecting resources).

7 *California Community Choice Association's Comments on Track 3.A Working Group Report*, Sept. 11, 2020 (CalCCA Report Comments) at 3-4.

8 SCE Comments at 3.

> upfront before the CPE works with the California Independent System Operator to determine the most effective fleet of resources.[9]

SCE correctly concludes that this approach would unnecessarily increase costs to customers.[10]

Removing the step of multiplying price by "effective" MW, as SCE proposes, will not eliminate an effectiveness evaluation of shown resources. Effectiveness will be considered in any decision by the CPE in assessing the value of a shown local RA resource. If the shown price overvalues effectiveness, the CPE will decline to take the resource, so the risk of overvaluation is on the showing LSE. CalCCA thus supports the following changes to Ordering Paragraph 3 proposed by SCE:

> • Year 1: Use the weighted average price from the last four quarters of Energy Division Power Charge Indifference Adjustment (PCIA) responses for both system and local RA; subtract system Resource Adequacy (RA) price from local RA price ~~**and multiply by effective MW**~~.
>
> • Subsequent Years: Use the weighted average price from the last four quarters of Energy Division PCIA responses for system RA and the most recent weighted average price reported in the CPE solicitation results (prior year's results) for local RA price; subtract system RA price from local RA price ~~**and multiply by effective MW**~~.

III. CONCLUSION

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

Respectfully submitted,

Evelyn Kahl

Evelyn Kahl
General Counsel to the
California Community Choice Association

November 17, 2020

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9 *Ibid.*
10 *Ibid.*

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

Expedited Application of Pacific Gas and Electric Company Under the Power Charge Indifference Adjustment Trigger. (U 39 E)	Application 20-09-014 (Filed September 28, 2020)
Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2021 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation. (U 39 E)	Application 20-07-002 (Filed July 1, 2020)

JOINT MOTION FOR APPROVAL OF SETTLEMENT AGREEMENT OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E), CALIFORNIA COMMUNITY CHOICE ASSOCIATION, JOINT CCAS, AND THE UTILITY REFORM NETWORK

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Dated: November 20, 2020

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JOINT MOTION FOR APPROVAL OF SETTLEMENT AGREEMENT OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E), CALIFORNIA COMMUNITY CHOICE ASSOCIATION, JOINT CCAS, AND THE UTILITY REFORM NETWORK

I. INTRODUCTION

In accordance with Rules 12.1 and 1.8(d) of the California Public Utilities Commission's ("Commission") Rules of Practice and Procedure, the California Community Choice Association ("CalCCA") and the Joint CCAs[1/] (together, the "CCAs"), The Utility Reform Network ("TURN"), and Pacific Gas & Electric Company ("PG&E") (collectively, "Settling Parties"), hereby jointly request that the Commission approve the Settlement Agreement, which is attached

1/ The Joint CCAs consist of Central Coast Community Energy, CleanPowerSF (the CCA for the City and County of San Francisco ("San Francisco"), which is operated by the San Francisco Public Utilities Commission; San Francisco is the Party to this proceeding), East Bay Community Energy, Marin Clean Energy, Peninsula Clean Energy Authority, Pioneer Community Energy, San José Clean Energy, Silicon Valley Clean Energy Authority, Sonoma Clean Power, and Valley Clean Energy Alliance.

to this Joint Motion ("Settlement Agreement").[2/] The Settlement Agreement resolves all of the disputed issues in the Power Charge Indifference Adjustment Undercollection Balancing Account ("PUBA") Trigger proceeding (A.20-09-14) as well as certain discovery and other disputes in the Energy Resource Recovery Account ("ERRA") Forecast Application (A.20-07-002). All remaining issues for resolution by the Commission already have been briefed.

The Settlement Agreement is in the public interest, represents a fair and equitable resolution of the issues, and achieves the stated goal of mitigating rate volatility and rate design complexity while still supporting resolution of the Consolidated Proceedings in time to implement new rates on January 1, 2021. The consolidated proceedings are nearing completion: the matters are to be submitted today (November 20), with a Proposed Decision on December 7, Opening Comments on December 11, and Reply Comments on December 15. The Settling Parties respectfully submit that timely approval of the Settlement Agreement will reduce the number of outstanding issues that remain in dispute in the proceeding and eliminate a potential obstacle to January 1, 2021 rate implementation. Approval of the Settlement Agreement will also reduce the administrative and resource burden on the Commission and the Settling Parties in future years and is otherwise in the public interest. Thus, the Settlement Agreement should be timely approved by the Commission without modification.

In addition, all parties to the Consolidated Proceedings have agreed to shorten the comment period for the motion to the approve the Settlement Agreement.[3/] The parties have

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2/ Pursuant to Rule 1.8(d), PG&E represents that counsel for Joint CCAs, CalCCA, and TURN have authorized PG&E to file this motion on behalf of their respective organizations. Counsel for Direct Access Customer Coalition ("DACC") authorized PG&E to represent that DACC does not oppose the Settlement Agreement. Counsel for Alliance for Retail Energy Markets ("AReM") authorized PG&E to represent that AReM takes no position on the Settlement Agreement. Counsel for the Public Advocates Office authorized PG&E to represent that the Public Advocates Office does not oppose the Settlement Agreement.

3/ Counsel for DACC, AReM, Modesto Irrigation District, Merced Irrigation District, Agricultural Energy Consumers Association, California Farm Bureau Federation, Sunrun, and the Public Advocates Office have authorized PG&E to represent that they either support or do not oppose the shortened comment period.

agreed to file any comments on the Settlement Agreement no later than Tuesday, November 24, 2020, with any reply comments due on Wednesday, November 25, 2020.[4/]

II. PROCEDURAL BACKGROUND

A. PG&E 2021 ERRA Forecast Application (A.20-07-002).

PG&E filed its 2021 ERRA Forecast Application on July 1, 2020, requesting that the Commission adopt its forecasted 2021 electric sales and peak load forecasts, revenue requirements and rate proposals, greenhouse gas ("GHG") allowance revenue return proposal, and the reasonableness review of GHG administrative and outreach costs incurred in 2019 and forecasted for 2021. PG&E amended its Application on August 14, 2020, and provided Supplemental Testimony on July 17, 2020, to correct a known electric load forecast error and the impacted revenue requirement calculations presented in its July 1, 2020 Application.

On August 5, 2020, the Commission received responses or protests from DACC, the Joint CCAs (except the City and County of San Francisco), CalCCA, Merced Irrigation District and Modesto Irrigation District (the "Districts"), and the Public Advocates Office ("CalPA").

On August 12, 2020, Sunrun, Inc. ("Sunrun") moved for party status, which Administrative Law Judge ("ALJ") Wang granted at the prehearing conference.

A prehearing conference in A.20-07-002 was held on August 13, 2020, and the Scoping Memo was issued on September 10, 2020.

PG&E filed its reply to the protests and responses on August 17, 2020.

On September 14, 2020, the Agricultural Energy Consumers Association ("AECA") moved for party status, which ALJ Wang granted on September 14, 2020.

On September 22, 2020, the City and County of San Francisco moved for party status, which ALJ Wang granted on September 23, 2020.

4/ To the movants' knowledge, no party has indicated that it intends to file comments on, or otherwise oppose, the Settlement Agreement.

On September 24, 2020, the Joint CCAs, Sunrun, and AECA submitted intervenor testimony.

On October 2, 2020, PG&E served a Joint Case Management Statement.

On October 8, 2020, PG&E submitted its Rebuttal Testimony.

On October 13, 2020, ALJ Wang issued an e-mail ruling cancelling evidentiary hearings.

PG&E served an updated load forecast on October 26, 2020.

On October 30, 2020, PG&E, the Joint CCAs, Sunrun, and AECA submitted Opening Briefs.

On November 5, 2020, Commissioner Guzman Aceves issued an *Assigned Commissioner's Scoping Memo and Ruling* ("Amended Scoping Memo"), consolidating Application 20-09-014 with Application 20-07-002 and assigning both proceedings to ALJ Wang.

PG&E, the Joint CCAs, Sunrun, and AECA submitted Reply Briefs on November 9, 2020.

PG&E also served updated testimony on November 9, 2020 ("the November Update"). The November Update updated market price and load information, described changes to PG&E's portfolio that occurred since the Application was filed, and included market price benchmark information calculated by the Energy Division for use in the PCIA and Ongoing CTC calculations.[5/]

PG&E served an Amended November Update on November 18, 2020, to correct certain errors in the November Update.

Pursuant to the Scoping Memo, parties will file comments on the November Update by November 20, 2020.[6/]

5/ *See* D.12-12-008 at pp. 9-10 (describing the types of information included in PG&E's 2013 ERRA Forecast application update).

6/ Scoping Memo, p. 5.

B. PG&E 2020 PUBA Trigger Application (A.20-09-014).

On September 28, 2020, PG&E filed its first expedited application under the PCIA Trigger (A.20-09-014). The PCIA "cap and trigger" mechanism acts to limit the change in the PCIA rate from one year to the next, but also establishes an expedited application process to protect against excessive undercollections.[7/] In A.20-09-014, PG&E requests authorization to amortize the undercollected balance in the PCIA Undercollection Balancing Account ("PUBA") over a 12-month period beginning January 1, 2021 and concluding December 31, 2021, and to simultaneously refund bundled customers that same amount with interest.

The Joint CCAs, CalCCA, DACC, AReM, TURN, and CalPA filed responses or protests to the application prior to the October 19, 2020 deadline, raising issues regarding the allocation of responsibility for the PUBA balance and arguing for an extended amortization period. On October 23, PG&E filed its reply to the protests and responses.

A prehearing conference in A.20-09-014 was held on October 30, 2020.

Subsequently, on November 5, 2020, the Amended Scoping Memo consolidated A.20-07-002 and A.20-09-014, noting that the administrative simplicity of handling these applications in a consolidated manner outweighs any potential burden of consolidation.

A technical workshop to discuss A.20-09-014 was held on November 12, 2020.

PG&E and the Joint CCAs each filed Opening Briefs in A.20-09-014 on November 17, 2020.

On November 17, 2020, counsel for the Joint CCAs served a notice of Notice of Settlement Conference Pursuant to Rule 12.1 on all parties in the Consolidated Proceedings and obtained the consent of all parties to the Tuesday, November 18, 2020, settlement conference. As such, all parties have stipulated to reduce the time for notice or have waived the need for service. The settlement conference was held on November 18, 2020.[8/]

7/ D.18-10-019, Finding of Facts 19 and 24.

8/ Non-settling parties participating in the Settlement Conference included Cal Advocates.

III. SUMMARY OF SETTLEMENT TERMS

The Settlement Agreement resolves all outstanding issues in A.20-09-014, as well as certain issues in A.20-07-002. The remaining disputed issues in A.20-07-002 have already been fully briefed or the subject of comments, and the matter is submitted as of November 20, 2020. A description of the key terms of the Settlement Agreement, embodied in various paragraphs of the Settlement Agreement and not necessarily under these specific headings or order, are highlighted here.

Timing. Maintaining the current schedule for the proceeding is of the utmost importance to the Settling Parties. In the Settlement Agreement, the parties each acknowledge the importance of implementing rates on January 1, 2021, to mitigate rate volatility and rate design complexity for 2021 and beyond. The Settling Parties agree not to seek modifications to the adopted procedural schedule in the Consolidated Proceedings. Each Settling Party also agrees to refrain from raising as part of its comments on the November Update in PG&E's 2021 ERRA Forecast case issues for the Commission to resolve that have not been raised in the proceeding to date. In addition, each Settling Party agrees to implementation of PG&E's 2021 ERRA Forecast requests and the return of the PUBA balance via a Tier 1 advice letter. Finally, the Settling Parties acknowledge that delay of a final decision in A.20-07-002 and A.20-09-014 beyond December 17, 2020, would invalidate the basis for the proposal, which is premised on implementation of rates on January 1, 2021.

Amortization Period for PUBA Balance. The Settling Parties agree that, unless certain enumerated events occur, the forecast year-end 2020 PUBA balance should be amortized over three calendar years beginning upon approval of the settlement in 2021, with one-third (1/3) of the year-end 2020 PUBA balance being collected in each of 2021, 2022, and 2023.[9/] This extended amortization period, when combined with other provisions of the Settlement Agreement relating to PCIA rates for 2021, will provide increased rate certainty and reduced rate

9/ PG&E's PUBA Trigger Application (A.20-09-014) had proposed to amortize the year-end 2020 PUBA balance over a 12-month period.

volatility for the affected Settling Parties in the coming years, while simultaneously lowering the likelihood of, if not eliminating, the need for future PCIA trigger applications and disputes around the return of the PUBA balance to bundled customers.

Petition for Modification. The Settling Parties agree that it is in their mutual interest to permanently eliminate the PCIA cap and trigger mechanism. Accordingly, the Settling Parties agree to affirmatively support the termination of the entire PCIA cap-and-trigger framework via a joint Settling Parties' petition for modification ("PFM") of D.18-10-019 to be filed in early 2021.

Uncapped PCIA Rates for 2021. The Settling Parties request that the Commission waive application of the PCIA rate cap for 2021, pending resolution of the forthcoming PFM (*i.e.*, the cap would not be applied in the calculation of the 2021 PCIA Base Rate for PCIA-eligible departing load). Instead, if the Settlement Agreement is approved by the Commission, the 2021 PCIA Total Rate for PCIA-eligible departing load would be the sum of two items: the 2021 PCIA Base Rate and the 2021 PCIA Rate Adder. The 2021 PCIA Base Rate is based on uncapped 2021 revenue requirements. The 2021 PCIA Rate Adder amortizes one third of the forecasted year-end 2020 PUBA in the year 2021. This aspect of the Settlement Agreement, when combined with other provisions of the Settlement Agreement relating to the amortization period for the current PUBA balance, will provide increased rate certainty and reduced rate volatility for affected Settling Parties in the coming years, while simultaneously lowering the likelihood of, if not eliminating, the need for future PCIA trigger applications and disputes around the return of the PUBA balance to bundled customers.

Master Data Request. PG&E and the CCAs have engaged in ongoing disagreements and discovery disputes over the past several ERRA cycles, primarily related to the timing and breakdown of actual recorded balances provided in the ERRA Forecast proceeding. To resolve those disputes, PG&E has agreed to provide, as part of a Master Data Request ("MDR") response in each of its future ERRA Forecast proceedings, certain specified information to the Settling Parties' reviewing representatives within a reasonable timeframe after each of PG&E's

monthly ERRA/PABA/PUBA activity reports are submitted to the Commission during the pendency of the applicable ERRA Forecast proceeding. The Settling Parties further agree that the purpose of the MDR is to support an aggregated review of PG&E's recorded entries to the PABA; the detailed review and audit of recorded entries in the balancing accounts will continue to be performed in connection with the ERRA Compliance Review proceeding (not in PG&E's ERRA Forecast proceeding).

Settlement Not Approved. As noted above, timely resolution of this proceeding is a critical component of the Settlement Agreement. However, if the Commission rejects the Settlement Agreement because of substantive concerns with its terms or is unable to issue its decision on the Settlement Agreement for rate implementation on January 1, 2021, the Settlement Agreement reflects the parties support for collecting the entire forecasted year-end 2020 PUBA balance in 2021, as proposed by PG&E in A.20-09-014.

The full text of the Settlement Agreement is provided as Attachment A.

IV. REQUEST FOR APPROVAL OF SETTLEMENT AGREEMENT

The Commission will approve a settlement if it finds the settlement "reasonable in light of the whole record, consistent with law, and in the public interest."[10/]

A. The Settlement Is Reasonable in Light of the Whole Record.

The Settling Parties are knowledgeable and experienced regarding the issues in the Consolidated Proceedings and represent distinct and affected interests:

- PG&E, which is responsible for procuring power to serve its bundled customers and whose stranded procurement costs are recovered through the PCIA;
- Joint CCAs, which represent ten community-based energy suppliers serving PG&E unbundled customers that pay the PCIA;
- CalCCA, which represents the interests of California's community choice electricity providers statewide;

10/ Rule 12.1(d).

- TURN, which is an independent statewide utility ratepayer advocacy organization and the original sponsor of the PCIA cap and trigger mechanism;

The Joint CCAs, in particular, have been active parties in PG&E's ERRA Forecast and ERRA Compliance proceedings for many years.

The Settling Parties reached agreement after the submission of lengthy testimony, extensive discovery, careful analysis of issues, and settlement discussions. With respect to the overall agreement by the Settling Parties regarding A.20-09-014, including agreement on both the amortization period and PUBA amounts, all disputed issues have been resolved. Moreover, the evidence in the proceeding, including the differences in capped and uncapped PCIA rates for 2021, the forecasted PUBA balances for 2021, and the likelihood of a PUBA trigger application next year—all which are eliminated if the Commission adopts the Settlement Agreement—demonstrate that it is in Settling Parties' mutual interest to adopt the Settlement Agreement. The fact that PG&E, CalCCA, Joint CCAs, and TURN were able to find common ground in areas where they originally (and historically) differed indicates that the Settlement Agreement is reasonable in light of the whole record and reflects a reasonable balance of the various interests affected by these proceedings.

B. The Settlement Is Consistent with the Law.

In agreeing to the terms of the Settlement Agreement, the Settling Parties considered the relevant statutes, rules and Commission decisions. Procedurally, the settlement process was conducted in accordance with Rule 12 of the Commission's Rules of Practice and Procedure. Notice of a settlement conference was provided, as required by Rule 12.1(b), and a settlement conference was conducted by the Joint Parties on November 18, 2020.

Substantively, the Settling Parties believe that the terms of the Settlement Agreement comply with all applicable statutes. Applicable statutes include Public Utilities Code § 451, which requires that utility rates must be just and reasonable, Public Utilities Code § 454, which prevents a change in public utility rates unless the Commission finds such an increase justified; Public Utilities Code § 454.5, which provides for timely recovery of procurement costs incurred pursuant to an approved procurement plan and requiring the commission establish rates based on forecasts of such procurement costs; and Public Utility Code §§ 366.1 and 366.2, which require the Commission to make sure that customers leaving utility service do not burden remaining utility customers with costs which were incurred to serve them. Moreover, the Commission has the authority to waive application of a principle announced in a prior decision, particularly where all affected parties to the proceeding are either Settling Parties or have indicated their non-opposition to the Settlement Agreement.

C. The Settlement Is in the Public Interest.

The Commission has a "long-standing policy favoring settlements."[11/] As the Commission has stated, the "Commission favors settlements because they generally support worthwhile goals, including reducing the expense of litigation, conserving scarce Commission resources, and allowing parties to reduce the risk that litigation will produce unacceptable results."[12/] Furthermore, the Commission has held that a settlement that "commands broad support among participants fairly reflective of the affected interests" is an important factor in the "public interest" criterion.[13/] Furthermore, Commission policy "weighs against the Commission's alteration of agreements reached through negotiation."[14/]

Here, the Settlement Agreement is consistent with the Commission's policy in support of settlement. Adoption of the Settlement Agreement will conserve the Commission's resources and achieve a final resolution of this proceeding in less time, and at less cost, to the public and the Settling Parties than would be the case if this matter were to be fully litigated. Perhaps as important, the Settlement Agreement will avoid the need for PG&E to file a PUBA Trigger Application in 2021 and, depending on the Commission's decision on the contemplated PFM, in

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11/ D.10-06-038 at p. 46.

12/ D.10-12-035 at p. 87; D.10-11-035 at p. 17.

13/ *See Decision Approving Settlement Agreement for Southern California Edison Company's and Pacific Gas and Electric Company's Economic Development Rate Program* (D.10-06-015), dated June 3, 2010 at 11-12, citing 1992 Cal. PUC LEXIS 867 at 16.

14/ D.06-06-014 at p. 12.

perpetuity. Avoiding the need for PUBA Trigger Applications in 2021 and beyond would significantly reduce the administrative and resource burden of the Settling Parties and the Commission in the coming years, promote rate stability, and save customers money in the process. This Settlement Agreement is also in the public interest because it resolves lingering disputes around data access that have lasted over several ERRA cycles, thus ending further litigation time and costs for the Settling Parties and the Commission in future ERRA Forecast proceedings.

The Settlement Agreement is sponsored by the PG&E, CalCCA, the Joint CCAs, and TURN, and therefore is supported, or not opposed, by participants who fairly reflect the affected interests, and it does not contravene statutory provisions, as discussed above.[15/] All Settling Parties seek a fair and balanced resolution of this matter and support adoption of the Settlement Agreement as such. Together, the Settling Parties' collective agreement to recommend adoption of the Settlement Agreement supports the notion that the settlement is in the public interest.

V. THE COMMISSION SHOULD ACT IN AN EXPEDITED MANNER

The Settling Parties request that the Commission consider this motion on an expedited basis to ensure timely implementation of 2021 rates. As noted above, if the Commission does not approve the Settlement Agreement and issue a final decision in the consolidated cases by December 17, 2020, the Settlement Parties acknowledge this would invalidate the basis for the proposal, which is premised on implementation of rates on January 1, 2021. Thus, expedited action is essential.

VI. THE COMMISSION SHOULD SHORTEN THE COMMENT PERIOD

In recognition of the need for prompt action to maintain the proceeding's current schedule, all parties to both proceedings support a shortened comments period on the Settlement Agreement. All parties to the Consolidated Proceedings have agreed to file any comments on the

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15/ As noted above, DACC, which advocates on behalf of direct access interests, does not oppose the settlement.

Settlement Agreement no later than Tuesday, November 24, 2020, with any reply comments due on Wednesday, November 25, 2020.

VII. CONCLUSION

As demonstrated above, the Settlement is reasonable in light of the whole record, consistent with law, and in the public interest. Thus, the Settling Parties respectfully request that the Commission approve the Settlement without modification in accordance with the current schedule for these Consolidated Proceedings.

Respectfully submitted on behalf of Settling Parties,

By: */s/ Tyson R. Smith*
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Dated: November 20, 2020

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT A

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2021 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U 39 E)	Application No. 20-07-002 (Filed July 1, 2020)
Expedited Application of Pacific Gas and Electric Company Under the Power Charge Indifference Adjustment Trigger. (U 39 E)	Application No. 20-09-014 (Filed September 28, 2020) (Consolidated)

SETTLEMENT AGREEMENT BETWEEN PACIFIC GAS AND ELECTRIC COMPANY (U 39 E), THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION, THE JOINT COMMUNITY CHOICE AGGREGATORS, AND THE UTILITY REFORM NETWORK

Pacific Gas and Electric Company ("PG&E"), the California Community Choice Association ("CalCCA"), the Joint Community Choice Aggregators ("Joint CCAs"),[1] and The Utility Reform Network ("TURN"), (collectively, the "Settling Parties") enter into this Settlement Agreement as a compromise of their respective litigation positions to resolve all disputed issues raised in the *Expedited Application of Pacific Gas and Electric Company Under the Power Charge Indifference Adjustment Trigger (U 39 E)* ("PCIA Trigger Application") and

1/ The Joint CCAs consist of Central Coast Community Energy, CleanPowerSF (the CCA for the City and County of San Francisco ("San Francisco"), which is operated by the San Francisco Public Utilities Commission; San Francisco is the Party to this proceeding), East Bay Community Energy, Marin Clean Energy, Peninsula Clean Energy Authority, Pioneer Community Energy, San José Clean Energy, Silicon Valley Clean Energy Authority, Sonoma Clean Power, and Valley Clean Energy Alliance.

certain disputed issues raised in the *Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2021 Energy Resource Recovery Account ("ERRA") and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U 39 E)* ("ERRA Forecast Application") before the California Public Utilities Commission ("CPUC" or "Commission").

The Settling Parties have negotiated the terms and conditions of this Settlement Agreement to resolve (1) all disputed issues in A.20-09-014, including the amortization of the forecasted year-end 2020 Power Charge Indifference Amount ("PCIA") Undercollection Balancing Account ("PUBA") balance, (2) the issue of whether PCIA rates will be capped as a result of the ERRA Forecast Application, (3) the issue of whether PG&E has supported its proposed rates in the ERRA Forecast Application with substantial evidence[2], and (4) the issue of PG&E providing more data to parties in the ERRA Forecast Application. The remaining disputed issues in the ERRA Forecast Application have already been briefed by the parties, and may be addressed further in comments on November 20, 2020 in the limited manner described herein, for resolution by a Commission decision.

Any undisputed proposals or requests for relief in the ERRA Forecast Application and ERRA Trigger Application shall be deemed unopposed by CalCCA, the Joint CCAs, and TURN. The Settling Parties request that the Commission approve those proposals and requested relief as presented.

I. SETTLEMENT PROCESS

On November 17, 2020, the Joint CCAs provided Notice of Settlement Conference to the service list pursuant to Commission Rules of Practice and Procedure (Rule) 12.1(b). The Settlement Conference was conducted remotely via web conference at 4 p.m. on November 18, 2020. Settling Parties participating in the Settlement Conference included PG&E, the Joint CCAs, CalCCA, and TURN. Non-settling parties participating in the Settlement Conference

[2] TURN's support for the settlement extends only to the disputed issues raised in A.20-09-014 and does not constitute support for the overall reasonableness of proposed rates in the ERRA forecast application.

included Cal Advocates, the Direct Access Customer Coalition, and the Alliance for Retail Energy Markets, and the Public Advocates Office at the California Public Utilities Commission.

The Joint CCAs, CalCCA, and TURN have reviewed PG&E's PCIA Trigger Application and ERRA Forecast Application and all applicable testimony, workpapers, and responses to discovery requests, and conclude that the Commission's final decision in this proceeding should approve all of the relief requested in PG&E's applications, except as expressly provided in this Settlement Agreement and except for the issues in the ERRA Forecast Application that have been addressed in briefing, will be addressed in comments on the November Update, remain in dispute, are unresolved by this Settlement Agreement, and are reserved for Commission decision.

II. SETTLEMENT AGREEMENT TERMS AND CONDITIONS

The Settling Parties agree to the following terms and conditions:

1. The Settling Parties each acknowledge the importance of implementing rates on January 1, 2021, to mitigate rate volatility and rate design complexity. Each Settling Party agrees to support, and CalCCA agrees to cause its members to support (or not oppose), the adopted procedural schedule in the 2021 ERRA Forecast proceeding, i.e., no further requests for modification. TURN agrees not to propose changes to the schedule. In addition, each Settling Party agrees to implementation of PG&E's 2021 ERRA Forecast Application and the return of the PUBA balance via a Tier 1 advice letter.

2. To facilitate implementation of the settlement agreement in a timely manner, each Settling Party agrees to support, and CalCCA agrees to cause its members to support (or not oppose), that PG&E's year-end 2020 Portfolio Allocation Balancing Account ("PABA") balance in PG&E's 2021 ERRA Forecast Application is supported by substantial evidence. TURN agrees not to oppose this finding. Each Settling Party also agrees to refrain from raising as part of its comments on the November Update in PG&E's 2021 ERRA Forecast Application issues for the Commission to resolve that have not been raised in the proceeding to date.

3. PG&E agrees to provide to any party to the proceeding as part of a Master Data Request ("MDR") response in each of its future ERRA Forecast proceedings, the following:

    a. Confidential versions of the monthly ERRA/PABA/PUBA activity reports.

    b. Additional detail supporting the monthly PABA reports, including subcategories for summarized line items such as Utility-Owned Generation ("UOG") costs and Contracts (e.g., provide by resource type, and whether Renewable Portfolio Standard ("RPS") or non-RPS eligible).

    c. Actual volumetric quantities underlying each relevant dollar figure; such categories include UOG generation, power purchases and sales, California Independent System Operator market sales, and retail customer sales.

    d. Monthly volumes of Actual Sold, Retained, and Unsold Resource Adequacy capacity.

    e. Monthly volumes of Actual Sold, Retained, and Unsold RPS-eligible energy.

    Non-confidential information will be provided to all parties to the proceeding that request a copy of the MDR response. A party's access to confidential information within the MDR will require its reviewing representative to sign a nondisclosure agreement. PG&E will provide the specified information to the Settling Parties' reviewing representatives within a reasonable timeframe after each of PG&E's monthly ERRA/PABA/PUBA activity reports is submitted to the Commission during the pendency of the applicable ERRA Forecast proceeding.

4. PG&E agrees to update the relevant actual recorded components of the MDR within a reasonable timeframe after each of its monthly ERRA/PABA/PUBA reports is filed during the pendency of the applicable ERRA Forecast proceeding. The Settling Parties agree that the purpose of the MDR is to support a Settling Party's aggregated review of PG&E's recorded entries to the PABA. The detailed review and audit of recorded entries in the balancing accounts is performed in connection with the ERRA Compliance Review proceeding and not in PG&E's ERRA Forecast proceeding.

5. Each Settling Party agrees to affirmatively support, and CalCCA agrees to cause its members to support (or not oppose), the termination of the entire PCIA cap-and-trigger framework via a joint Settling Parties' petition for modification ("PFM") of D.18-10-019 to be filed in early 2021.

6. The Settling Parties agree to seek the Commission's waiver of the PCIA rate increase cap in 2021 (*i.e.*, the cap would not be applied in the calculation of the 2021 PCIA Base Rate for PCIA-eligible departing load). The 2021 PCIA Base Rate does not include amortization of the forecasted year-end 2020 PUBA balance, which is addressed in Paragraphs 7-9.

7. The Settling Parties agree, in determining the 2021 PCIA Total Rate for PCIA-eligible departing load, to combine the final uncapped 2021 ERRA Forecast revenue requirement adopted in A.20-07-002 (PCIA Base Rate) and, upon approval of this settlement, one-third (1/3) of the forecasted year-end 2020 PUBA balance for recovery in 2021 (2021 PUBA Rate Adder). The 2021 PCIA Total Rate for PCIA-eligible departing load would be the sum of the 2021 PCIA Base Rate and the 2021 PCIA Rate Adder.

8. Except as provided below, the forecasted year-end 2020 PUBA balance will be amortized over three calendar years beginning upon approval of the settlement in 2021, with one-third (1/3) of the forecasted year-end 2020 PUBA balance being collected in each of 2021, 2022, and 2023.

9. Amortization of the year-end 2020 PUBA balance over 2021, 2022, and 2023 is contingent on the Settling Parties' joint PFM of D.18-10-019 being filed in early 2021, supported by the Settling Parties, and the members of CalCCA (or its members do not oppose it), and approved in 2021.

    a. If the Settling Parties fail to support (or not oppose) the PFM, the remaining 2/3 amortization of the year-end 2020 PUBA balance is collected in 2022, and amortization of any residual year-end 2021 PUBA balance will be collected in 2022. In this circumstance, if PG&E "triggers" due to the PUBA accruing in 2021, PG&E agrees to propose disposition of the PUBA balance in connection with its 2022 ERRA Forecast proceeding (*i.e.*, PG&E will not seek to implement a mid-year 2021 rate increase to address the PUBA balance).

b. The Settling Parties agree to use all reasonable efforts to obtain approval of the PFM in 2021. If the PFM is still pending on the date by which the November Update must be submitted in 2021, the Settling Parties agree to seek the Commission's waiver of the PCIA rate increase cap in 2022 (*i.e.*, the cap will not be applied in the calculation of the 2022 PCIA Base Rate for PCIA-eligible departing load).

10. Each Settling Party agrees to work with PG&E in good faith to secure prompt Commission approval of this settlement and to not oppose – and CalCCA agrees to cause its members to not oppose – the settlement or any terms of the settlement in any proceeding.

11. This settlement will be binding on the parties except as specified in Paragraph 19.

12. If the CPUC rejects the settlement, as specified in Paragraph 19, amortization of the entire forecasted year-end 2020 PUBA balance will be collected in 2021 as proposed by PG&E in A.20-09-014, and amortization of any year-end 2021 PUBA balance will be collected in 2022. In this circumstance, if PG&E "triggers" due to the PUBA accruing in 2021, PG&E agrees to propose disposition of the PUBA balance in connection with its 2022 ERRA Forecast proceeding (*i.e.*, PG&E will not seek to implement a mid-year 2021 rate increase to address the PUBA balance).

13. This settlement agreement resolves all outstanding issues in A.20-09-014 and the issues identified above in Paragraphs 1-4 and 6 in A.20-07-002. All other outstanding issues in A.20-07-002 remain unresolved.

14. The Settling Parties agree to file a motion for approval of this settlement by the Commission no later than November 20, 2020, *provided that* all parties to A.20-07-002 and A.20-09-014 agree to shortened opening and reply comment periods on any settlement. Moreover, the settling parties each agree that, consistent with CPUC Rule 12(c), the motion for approval of this settlement shall state that delay of a final decision

in A.20-07-002 and A.20-09-014 beyond December 17, 2020, would invalidate the basis for the proposal and shall also clearly state the timing urgency for a final decision.

III. GENERAL PROVISIONS

15. Unless the Commission expressly provides otherwise, and except as otherwise expressly provided herein, such Commission adoption of the Settlement Agreement does not constitute approval or precedent for any principle or issue in this or any future proceeding.
16. The Settling Parties agree that nothing contained in this Settlement Agreement is to be construed as an admission of liability, fault, or improper action by any Settling Party.
17. The Settling Parties agree that this Settlement Agreement is subject to approval by the Commission. As soon as practicable after the Settling Parties have signed this Settlement Agreement, the Settling Parties shall jointly file a motion for Commission approval and adoption of the Settlement Agreement. The Settling Parties will furnish such additional information, documents, and/or testimony as the ALJ or the Commission may require in granting the motion adopting this Settlement Agreement.
18. The Settling Parties agree to recommend that the Commission approve and adopt this Settlement Agreement in its entirety without change.
19. The Settling Parties agree that, if the Commission fails to adopt this Settlement Agreement in its entirety and without modification, the Settling Parties shall convene a Settlement Agreement conference within two (2) business days thereof to discuss whether they can resolve the issues raised by the Commission's actions. If the Settling Parties cannot mutually agree to resolve the issues raised by the Commission's actions, the Settlement Agreement shall be rescinded, and the Settling Parties shall be released from their obligation to support the Settlement Agreement. Thereafter, the Settling Parties may pursue any action they deem appropriate but agree to cooperate in establishing a procedural schedule.

20. The Settling Parties agree to actively and mutually defend the Settlement Agreement if its approval and adoption is opposed by any other party.

21. This Settlement Agreement constitutes a final Settlement Agreement of:

    a. All disputed issues in the PCIA Trigger Application, A.20-09-014,

    b. The issue of whether PCIA rates will be capped as a result of the 2021 ERRA Forecast Application;

    c. The issue of whether PG&E has supported its proposed rates in the ERRA Forecast Application with substantial evidence[3], and

    d. The issue of PG&E providing more data to parties within future ERRA Forecast Applications.

    The few remaining disputed issues in the ERRA Forecast Application have already been briefed for resolution by a Commission decision and may be addressed in comments on the November Update on November 20, 2020 in the limited manner described herein.

22. This Settlement Agreement constitutes the Settling Parties' entire Settlement Agreement, which cannot be amended or modified without the express written and signed consent of all the Settling Parties hereto.

IV. MISCELLANEOUS PROVISIONS

23. The Settling Parties agree that no signatory to the Settlement Agreement or any employee thereof assumes any personal liability as a result of the Settlement Agreement.

24. If any Settling Party fails to perform its respective obligations under the Settlement Agreement, any other Settling Party may come before the Commission to pursue a remedy including enforcement.

25. The provisions of this Settlement Agreement are not severable. If the Commission, or any competent court of jurisdiction, overrules or modifies as legally invalid any material provision of the Settlement Agreement, the Settlement Agreement may be considered

[3] TURN's endorsement of the Settlement does not constitute support for the overall reasonableness of proposed rates in the ERRA Forecast Application.

rescinded as of the date such ruling or modification becomes final, at the discretion of the Settling Parties.

26. The Settling Parties acknowledge and stipulate that they are agreeing to this Settlement Agreement freely, voluntarily, and without any fraud, duress, or undue influence by any other party. Each Settling Party states that it has read and fully understands its rights, privileges, and duties under the Settlement Agreement, including each Settling Party's right to discuss the Settlement Agreement with its legal counsel and has exercised those rights, privileges, and duties to the extent deemed necessary.
27. In executing this Settlement Agreement, each Settling Party declares and mutually agrees that the terms and conditions are reasonable, consistent with law, and in the public interest.
28. No Settling Party has relied, or presently relies, upon any statement, promise, or representation by any other Settling Party, whether oral or written, except as specifically set forth in this Settlement Agreement. Each Settling Party expressly assumes the risk of any mistake of law or fact made by such Settling Party or its authorized representative.
29. This Settlement Agreement may be executed in separate counterparts by the different Settling Parties hereto with the same effect as if all Settling Parties had signed one and the same document. All such counterparts shall be deemed to be an original and shall together constitute one and the same Settlement Agreement.
30. This Settlement Agreement shall become effective and binding on the Settling Parties as of the date it is approved by the Commission in a final and non-appealable decision.
31. This Settlement Agreement shall be governed by the laws of the State of California as to all matters, including but not limited to, matters of validity, construction, effect, performance, and remedies.

The Settling Parties mutually believe that, based on the terms and conditions stated above, this Settlement Agreement is reasonable in light of the whole record, consistent with the

law, and in the public interest. The Settling Parties' authorized representatives have duly executed this Settlement Agreement on behalf of the parties they represent.

PACIFIC GAS AND ELECTRIC COMPANY

Robert S. Kenney

Robert S. Kenney
Vice President, Regulatory and External Affairs

Date: 11/20/20

CALIFORNIA COMMUNITY CHOICE ASSOCATION

Evelyn Kahl
General Counsel

Date:

JOINT COMMUNITY CHOICE AGGREGATORS

Tim Lindl
Attorney for the Joint CCAs

Date:

THE UTILITY REFORM NETWORK

Matthew Freedman
Attorney for TURN

Date:

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PACIFIC GAS AND ELECTRIC COMPANY	CALIFORNIA COMMUNITY CHOICE ASSOCATION
______________________	Evelyn Kahl
Robert S. Kenney Vice President, Regulatory and External Affairs	Evelyn Kahl General Counsel
Date: ____________	Date: November 20, 2020
JOINT COMMUNITY CHOICE AGGREGATORS	THE UTILITY REFORM NETWORK
______________________	______________________
Tim Lindl Attorney for the Joint CCAs	Matthew Freedman Attorney for TURN
Date: ____________	Date: ____________

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Robert S. Kenney
Vice President, Regulatory and External Affairs

Date: __________________

CALIFORNIA COMMUNITY CHOICE ASSOCATION

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Evelyn Kahl
General Counsel

Date: __________________

JOINT COMMUNITY CHOICE AGGREGATORS

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Tim Lindl
Attorney for the Joint CCAs

Date: November 20, 2020

THE UTILITY REFORM NETWORK

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Matthew Freedman
Attorney for TURN

Date: __________________

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Robert S. Kenney
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CALIFORNIA COMMUNITY CHOICE ASSOCATION

____

Evelyn Kahl
General Counsel

Date: ______________

JOINT COMMUNITY CHOICE AGGREGATORS

____

Tim Lindl
Attorney for the Joint CCAs

Date: ______________

THE UTILITY REFORM NETWORK

____

Matthew Freedman
Attorney for TURN

Date: 11/20/20

Comments on Preliminary Portfolio Analysis

Initiative: Resource adequacy enhancements

Comment period

Nov 12, 2020, 08:00 am - Nov 25, 2020, 05:00 pm

Submitting organizations

- California Community Choice Association (CalCCA)

California Community Choice Association (CalCCA)

Submitted on 11/25/2020, 04:19 pm

Submitted on behalf of
CalCCA

Contact
Evelyn Kahl, (415) 254-5454

1. Provide a summary of your organization's comments on the preliminary portfolio analysis:

CalCCA appreciates the CAISO's efforts in setting up, performing and sharing the results of the RA Enhancements Preliminary Portfolio Analysis (Portfolio Analysis). It is obvious that a lot of effort and thought was put into this work. We offer below some observations and questions related to the Portfolio Analysis.

2. Provide your organization's feedback on the Overview of the CAISO's Production Simulation Model topic as described in section 4:

CalCCA continues to support the use of a modified version of the production simulation model CAISO uses for the Summer Assessment for the portfolio assessment. CalCCA believes, however, that there is considerable value in modeling only the shown RA resources in all hours (i.e., peak and off-peak), as well as a scenario that includes all WECC resources, in and outside of California. The purpose of the portfolio assessment is to identify instances in which the shown RA resources would not be able meet the performance metric, which cannot be ascertained if non-RA resources are included in the assessment. At the same time, it is critical to understand the impact of including all WECC resources, which have every incentive to offer their available energy and capacity into the CAISO markets due to regional and diurnal diversity. The performance of the entire WECC portfolio thus should be considered when determining the appropriate service level reliability target in this stakeholder process, and understanding both scenarios is critical to understanding the risks of not meeting the performance target solely with the RA Portfolio. CalCCA also believes including the Thermal Portfolio provides a useful benchmark for comparison.

3. Provide your organization's feedback on the defining "deficiency" topic as described in section 4.1:

CalCCA supports the use of a metric to identify resource deficiencies that would have triggered a Stage Two Emergency but suggests CAISO refrain from characterizing this as a loss of load expectation as these are not equivalent concepts. Nevertheless, it seems reasonable to identify instances in which the model shows there would be inadequate capacity to meet load plus non-spinning reserves plus spinning reserves plus regulation, since CAISO would need to obtain emergency supply in these circumstances. As CAISO has noted, the service level reliability criteria to apply and the cost tradeoffs are critical elements that need further investigation in coordination with local regulatory authorities, since these entities are responsible for making the cost/benefit determination in consultation with CAISO as the Balancing Authority.

4. Provide your organization's feedback on the iterations and output topic as described in section 4.2:

CalCCA understands that the Portfolio Assessment modeled performance of the July 2020 shown RA fleet using stochastic production simulation with 2,000 month-long iterations to compute the probability of a portfolio deficiency with hourly, daily and monthly granularity. The hourly level data can be used to assess the hours in which CAISO is most likely to need additional capacity and the duration of the deficiencies. The daily level results show the probability of a deficiency within a day and identifies the magnitude of the largest daily deficiency. CalCCA understands that the more granular data increases the robustness of the simulation results.

5. Provide your organization's feedback on the model details topic as described in section 4.3 and all relevant subsections:

<u>Section 4.3.1 CAISO System:</u> CalCCA supports the use of a WECC-wide model to capture regional interactions that have a critical impact on CAISO's access to external resources. While CAISO does not have access to the same level of detailed information about the non-CAISO loads and resources, the regional model data is readily available to CAISO and already is used extensively by CAISO in the transmission planning process and as part of its operational planning. CalCCA suggests net imports be limited to the amount of Shown RA resources during both peak and off-peak hours for at least one of the scenarios. If imports are thus limited, CAISO may be able to consider running a California-only model for the Shown RA portfolio analysis, since the remaining WECC resources will not be relevant to the analysis. This reduction in the model should significantly reduce model run-time and thus allow for potentially more complex modeling assumptions, such as the correlation between loads and intermittent resource availability. CalCCA supports focusing on system level requirements and continuing to separately use the specialized assessment performed for local capacity requirements. We note, however, that in many local capacity areas/sub-areas, CAISO needs all or nearly all available local resources and these resources might not be included on RA showings. If CAISO ultimately is likely to have access to these resources (e.g., via backstop procurement), the impact of these resources ultimately being procured needs to be factored in to avoid over procurement of system resources. That is, parties should not be encouraged to cure system resource adequacy deficiencies that would then be rendered moot by CAISO's backstop procurement of needed local capacity resources.

<u>Section 4.3.2 Load Inputs:</u> CAISO has developed 175 hourly load profiles based on historical weather data. The distribution of loads depicted in Figure 1 for the July production simulation appear to be a reasonable representation of the distribution of potential load outcomes. CalCCA expects that if CAISO applies a similar approach to developing the load distributions for other months, it

likewise will result in reasonable representations of the range of potential outcomes to include in future simulations.

Section 4.3.3 Resource Inputs: CalCCA understands that CAISO has included historical production profiles for wind and solar resources in the RA Scenario, rather than using the ELCC MW for these resources. We agree that this is an appropriate approach for evaluating the impact of these Shown RA resources. Applying the ELCC MW would understate their expected impact during some hours and overstate their impact during other hours, greatly reducing the meaningfulness of the analysis. For the Thermal Scenario, CAISO has replaced the wind and solar resources with a representative mix of thermal resources, grossed up for the 15% planning reserve margin. CalCCA suggests that a more appropriate approach would be to replace the shown wind and solar ELCC MW with the thermal resources on a MW-for-ELCC MW basis. Had the wind and solar resources not been available to be shown, parties could have met their RA obligation by providing an equivalent MW amount of thermal resources without having to account for the actual production profile of the solar/wind resources and without having to account for the planning reserve margin beyond the amount already incorporated into the RA requirement.

In addition to the RA and Thermal Scenarios, CalCCA suggests CAISO should include two additional scenarios. The first would attempt to model the anticipated impact of the RA Enhancements UCAP proposal by grossing up the amount of conventional resources to address the expected increase in the RA requirement to account for the UCAP outages. We understand that this would be a hypothetical scenario and might also need to consider an adjustment to the overall obligation related to the potential decrease in the PRM from 15% to 10% associated with implementation of UCAP. We believe, however, that it would be a useful scenario for parties to consider informing the discussions related to development of the service level reliability criteria. The second scenario would be one in which all WECC-wide loads and resources would be modeled, whether or not they were included in RA showings. This scenario would be similar to the approach taken for the summer assessment to aid in identifying the potential risks related to the Shown RA deficiencies identified in the other scenarios.

CalCCA understands CAISO intends to model Hydro resources using similar water year production. This appears to be a reasonable approach, but if CAISO were to perform the portfolio modeling following the annual showings (rather than just for monthly showings), additional hydro uncertainty might need to be introduced into the modeling.

6. Provide your organization's feedback on the results topic as described in section 5:

CalCCA appreciates the CAISO's presentation of the results for the RA Scenario and the Thermal Scenario, which illustrate how the performance of the different RA fleets differ throughout the day (and, presumably, would differ throughout the year). These type of results (supplemented with additional analysis of portfolio performance in other months) help provide guidance for future procurement to help address the identified deficiencies. For example, the finding that over 90% of the days with deficiencies in both scenarios had deficiencies less than four hours duration suggests that four-hour storage resources could be useful for mitigating a large portion of the deficiencies.

The results suggest that the additional output of the modeled solar and wind resources above their ELCC contribute to reduced chances of RA deficiencies during some intervals, while the converse is true during other intervals. As noted in response to question 5, modeling a UCAP scenario in which the amount of shown RA resources is increased to align with the increased UCAP RA requirements is likely to show there will be reduced levels of deficiencies once UCAP is implemented as part of the RA Enhancements. CalCCA believes that it is important for CAISO to include such a UCAP scenario in future analyses so parties can evaluate portfolio performance that incorporates this key element of the RA Enhancements proposal.

7. Provide your organization's feedback on the interim needs topic as described in section 6:

CalCCA appreciates that the CAISO agrees that a net-load peak RA requirement is essential, as proposed by SCE and CalCCA in Track 3b of the CPUC RA proceeding. Our expectation is that with the SCE/CalCCA approach, the gross load peak requirement will no longer be needed. Additional portfolio modeling that includes representative RA portfolios that would meet such a net-load requirement would be useful to ascertain whether it is likely to be necessary to maintain a gross load peak requirement. However, CalCCA is concerned that CAISO's proposal to develop an interim net-load peak RA requirement for the 2022 RA year lacks specificity and a proposed means of implementation and will divert resources from finalizing the RA Enhancements needed for the 2023 RA year implementation. Under such a short timeframe, the proposal is also not likely to have a meaningful impact on the amount of new RA resources that can be procured by the 2022 RA year. LSEs need an appropriate amount of lead-time to comply with such a requirement, which should be developed in concert with the CPUC.

8. Provide your organization's feedback on the proposed foundational framework as described in section 7:

CalCCA appreciates CAISO's discussion of the granularity of the RA program as a necessary component for determining the appropriate reliability standard and agrees that California's monthly RA construct introduces complexities in the application of that standard. Further, the monthly compliance construct leaves very little time for deficiencies to be addressed if identified in a month-ahead assessment. An annual standard could provide greater efficiency in RA procurement and a longer runway for addressing potential shortfalls. Finally, as noted in CAISO's report, even under a monthly construct an annual standard is required to ensure all months are bound by a single guiding reliability standard. While CalCCA supports further exploration of the relative advantages of an annual standard, the RA period chosen must ultimately be consistent between the CPUC and CAISO.

9. Additional comments on the preliminary portfolio analysis:

DECEMBER FILINGS

FILED
12/03/20
04:59 PM

**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 ESTABLISHING PROCESS FOR BACKSTOP PROCUREMENT REQUIRED BY DECISION 19-11-016

Evelyn Kahl, General Counsel
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December 3, 2020

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SUMMARY OF RECOMMENDATIONS

The California Community Choice Association recommends the following modifications of the proposed decision:

- Establish clear evaluation criteria for Commission staff to consider in weighing whether to bring a resolution forward ordering backstop procurement.

- Establish a clear linkage between potential enforcement actions and LSE showing evaluation criteria.

- Establish a procedure where a declaration would be used as evidence of compliance with Milestone 1 for resources acquired by contract.

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 ESTABLISHING PROCESS FOR BACKSTOP PROCUREMENT REQUIRED BY DECISION 19-11-016

The California Community Choice Association (CalCCA)[1] submit these comments pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure on the November 13, 2020 proposed *Decision Establishing Process for Backstop Procurement Required by Decision 19-11-016* (PD).

I. INTRODUCTION

The PD adopts a balanced approach to ensure new resources ordered under Decision (D.) 19-11-016 are developed and interconnected in a timely manner. CalCCA generally supports the framework proposed in the PD, and notes the PD's intent to allow staff discretion prior to triggering backstop procurement or enforcement actions as a reasonable and prudent approach in light of the wide range of potential causes and magnitudes of resource delays or cancellation.

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1 California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, CleanPowerSF, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, 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, Silicon Valley Clean Energy, Solana Energy Alliance, Sonoma Clean Power, Valley Clean Energy, and Western Community Energy.

CalCCA offers the following recommendations to enhance the PD and, to the extent practical, establish clear up-front expectations for self-procuring LSEs:

- Establish clear evaluation criteria for Commission staff to consider in weighing whether to bring a resolution forward ordering backstop procurement.
- Establish a clear linkage between potential enforcement actions and LSE showing evaluation criteria.
- Establish a procedure where a declaration would be used as evidence of compliance with Milestone 1 for resources acquired by contract.

While CCAs are actively working with their counterparties to ensure projects meet their intended Commercial Online Dates (COD), it is well understood that some fraction of projects in any procurement round will inevitably face delays or even cancellation. It is likely that the impacts of novel coronavirus (COVID) pandemic on supply chain, land use permitting, construction, interconnection, and other project phases may heighten this risk, though the degree of COVID-related impacts is not yet known. CalCCA looks forward to continuing its coordination with Commission staff to identify and mitigate these impacts to the extent they arise.

Despite the best efforts of both LSEs and developers, external factors may significantly influence the timely delivery of projects. These may include:

- Availability or deliverability of necessary materials, infrastructure, or other materials resulting from stay-at-home orders, import restrictions, or other COVID-related limitations.[2]
- Delays in permitting resulting from stay-at-home orders, social distancing requirements, or other COVID-related safety measures reducing the capacity of local and state government agencies responsible for permitting.[3]

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[2] Protect Global Supply Chains for Low-Carbon Technologies, *Nature*. https://www.nature.com/articles/d41586-020-02499-8.

[3] Permitting Options for Solar Installations During the COVID-19 Outbreak; https://www.seia.org/research-resources/permitting-options-solar-installations-covid19.

- Unforeseen permitting challenges, such as changes to the protected status of certain species under the California Endangered Species Act, which was recently undertaken for the western Joshua tree (*Yucca brevifolia*).[4]

- Delays in interconnection resulting from stay-at-home orders, social distancing requirements, or other COVID-related safety measures reducing the capacity of utility and Independent System Operator teams responsible for interconnection.

In addition to the significant lead time involved with initiating a new backstop procurement order, the potential delays listed above would not easily be remedied by backstop procurement. In fact, in the context of permitting and interconnection delays, it is likely that backstop procurement would be even further backlogged *behind* the in-process, though h delayed, procurement. Consequently, there are relatively few scenarios for which a project delay should rationally initiate new backstop procurement, echoing the PD's comments regarding "minor delays or other obstacles."[5]

II. THE COMMISSION SHOULD EXPAND ITS CRITERIA FOR EVALUATING LSE SHOWINGS IN CONSIDERING BACKSTOP PROCUREMENT

CalCCA supports the PD's approach of providing Commission staff discretion prior to ordering backstop procurement and agrees with the explicit criteria identified for consideration in the PD.[6] However, while the PD identifies criteria for evaluating LSE submissions, it is less obvious what criteria staff may use in determining whether, after evaluating the submissions, backstop procurement should be ordered. Specifically, the Commission should outline criteria used to inform staff discretion on the decision to order procurement, such as:

- Whether a project has a reasonable path to ultimate completion, despite delay.

- Whether a project delay is likely to trigger reliability deficiencies.

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4 California Fish and Game Commission Notice of Receipt of Petition; https://nrm.dfg.ca.gov/FileHandler.ashx?DocumentID=175217&inline.

5 PD at 13.

6 PD at 19.

- Whether newly ordered backstop procurement could reasonably be expected to come online prior to the delayed project.

These evaluation criteria would help inform Commission staff's decision to bring forth a resolution ordering backstop procurement. Providing clear criteria would also provide guidance for LSEs and developers. While backstop procurement is an important tool for use in the event LSEs fail to successfully contract for necessary resources, or contracted resources fail, it should be viewed as a last resort in the context of resource delays.

III. THE COMMISSION SHOULD LINK POTENTIAL OTHER ENFORCEMENT ACTIONS TO EVALUATION CRITERIA

Given the severe financial, operational, other impacts of backstop procurement on a deficient LSE, the PD proposes an alternate approach of exploring "compliance and/or enforcement actions" on deficient LSEs in lieu of ordering backstop procurement. Given the inevitability of delay and/or cancellation of some subset of procurement ordered by D.19-11-016 and the reality that the majority of delays and cancellations arise due to conditions beyond the control of LSE and developer, enforcement actions should only be considered if the delay or cancellation clearly lies within the control of one or both parties.

As discussed above, there are myriad causes for project delay and cancellation, many of which are exacerbated by the impacts of COVID. Of particular note, CalCCA is concerned that delays in the interconnection process may result in a project missing its COD, which is not a process controlled by individual LSEs. Given the significant number of new projects all targeting online dates on or before the compliance deadlines, it is likely that IOU interconnection teams may accrue an interconnection backlog resulting in delays beyond the control of the self-procuring LSE. This is but one of many circumstances under which it would not be prudent to undertake an enforcement action against the LSE.

IV. THE COMMISSION SHOULD PERMIT RELIANCE ON AN EXECUTIVE DECLARATION FOR CONTRACTED RESOURCES RATHER THAN THE SPECIFIED DOCUMENTS IDENTIFIED IN MILESTONE 1

The Commission should streamline Milestone 1 by requesting that LSEs submit a declaration from an executive stating that the LSEs holds a signed contract with a developer, that an interconnection agreement for the project in question exists, and that there are signed land leases or title deeds for the project in place. LSEs would submit this declaration along with a project timeline instead of the actual contract, interconnection agreement, and signed land leases or title deeds. The contracts and interconnection agreements are complex documents that are hundreds of pages long and in many cases cannot be shared without involving the counterparties. Thus, replacing the filing of actual contracts and agreements for each project that an LSE intends to use to meet its procurement obligation under D.19-11-016 with a declaration would refine Milestone 1 and facilitate Commission staff's review of the milestone.

V. CONCLUSION

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

Respectfully submitted,

Evelyn Kahl

Evelyn Kahl
General Counsel to the
California Community Choice Association

December 3, 2020

APPENDIX A

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

FINDINGS OF FACT

NEW Finding. In the case of contracted, presenting source documentation maintained by the project developer to the Commission to demonstrate fulfillment of the milestones creates a greater challenge than owned resources due to contract provisions limiting availability and disclosure of confidential information.

CONCLUSIONS OF LAW

NEW Conclusion of Law. Commission staff should develop and make available to all LSEs clear evaluation criteria that will guide the staff's consideration in weighing whether to bring a resolution forward ordering backstop procurement.

NEW Conclusion of Law. Enforcement actions should be clearly linked by Commission staff to the evaluation criteria guiding its determination of the need for backstop procurement.

NEW Conclusion of Law. A declaration from an executive that an LSE's project has met the relevant development milestones established by the Commission provides sufficient assurance of compliance when the underlying documents to demonstrate compliance are subject to contract provisions precluding disclosure of such documents.

ORDERING PARAGRAPHS

2. When making the compliance filings required in Ordering Paragraph 1 above, all load-serving entities subject to the requirements of Decision 19-11-016 who did not opt out of providing capacity for their customers shall include ~~information~~ direct evidence or a declaration from an executive addressing each of the following milestones for each of the three years of the capacity requirements (2021, 2022, and 2023):

Milestone 1**:** a signed contract with a resource developer for provision of commercial technology, an interconnection agreement with a demonstrated path toward deliverability by the required online date, signed land leases or title deeds demonstrating project site control, and a project timeline. This milestone may also show intended procurement from demand response resources, as well as allowable imports.

Milestone 2**:** a showing of a "notice to proceed" or similar contractual evidence of construction commencement for new construction projects, as well as executed contracts for demand response, imports, or sales of excess resources between LSEs.

Milestone 3: evidence of a project being online and capable of delivering energy, or in the case of demand response, load reduction.

NEW Ordering Paragraph. In advance of LSEs making compliance filings required in Ordering Paragraph 1, Commission staff shall make available to LSEs a list of evaluation criteria that will be considered in evaluating the need for backstop procurement. Any enforcement action shall be tied directly to the ability of an LSE to meet the evaluation criteria.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue the Development of Rates and Infrastructure for Vehicle Electrification.	))))))	Rulemaking 18-12-006

OPENING COMMENTS OF THE JOINT COMMUNITY CHOICE AGGREGATORS ON THE PROPOSED DECISION

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December 3, 2020

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

Order Instituting Rulemaking to Continue the Development of Rates and Infrastructure for Vehicle Electrification.	)))))	Rulemaking 18-12-006

**OPENING COMMENTS OF THE JOINT COMMUNITY CHOICE AGGREGATORS
ON THE PROPOSED DECISION**

In accordance with Rules 1.15 (Computation of Time) and 14.3 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission"), the Joint Community Choice Aggregators ("Joint CCAs") submit these opening comments on the *Proposed Decision Concerning Implementation of Senate Bill 676 and Vehicle-To-Grid Integration Strategies,* dated November 13, 2020 ("PD"). [1]

I. INDEX OF RECOMMENDED CHANGES

In accordance with Rule 14.3(b) and as supported below, the Joint CCAs provide the following subject index of recommended changes to the PD:

- The PD should be modified to clarify that the sections of the investor-owned utilities' ("IOUs") reporting template that are considered "relevant" for Community Choice Aggregators ("CCAs") will be determined at a later date through agreement with Energy Division staff.

- The PD should be modified to clarify that outcome-based metrics related to CCAs' "role providing energy" will also be determined at a later date through agreement with Energy Division staff.

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[1] The Joint CCAs consist of Marin Clean Energy ("MCE"), Sonoma Clean Power Authority ("SCP"), California Choice Energy Authority ("CalChoice"), Silicon Valley Clean Energy Authority ("SVCE"), East Bay Community Energy ("EBCE"), Peninsula Clean Energy ("PCE") and the City of San José. The group of CCAs that comprises the Joint CCAs, as defined in this filing, is not identical to the group of CCAs that has filed under this designation in prior filings in this docket.

II. OPENING COMMENTS

A. CCAs Are Strong Supporters of Maximizing the Use of Vehicle-Grid Integration Strategies

The Joint CCAs are strong supporters of vehicle-grid integration ("VGI") activities. This is evidenced by the fact that several CCAs have already developed managed charging pilots and/or demand response ("DR") programs for electric vehicles ("EVs"). For example, in October 2020, SVCE launched a pilot entitled "GridShift: EV Charging."[2] For this pilot, SVCE collaborated with the software company ev.energy to launch a mobile application that allows EV drivers to charge with the lowest cost clean energy available by automatically linking to the customer's EV rate and California Independent System Operator ("CAISO") grid emissions. The pilot is ongoing with a target participation of 200 residential households, and is leveraging EV telematics data to optimize carbon emission reductions and customer cost savings. As SVCE develops a broader virtual power plant program, findings from the GridShift: EV Charging pilot will be used to inform public charging as well as at-home VGI participation efforts.

Another example of an innovative CCA program is SCP's DR program: the GridSavvy Community.[3] The GridSavvy Community is built on the premise that customers can be an active solution to help decarbonize communities. The program has evolved over the years to include more than 2,900 smart devices, including 800 Level 2 EV charging stations, as well as other devices such as thermostats and heat pump water heaters, which are all capable of responding to grid signals. In addition to typical DR events that help reduce SCP's projected system peaks, SCP dispatched this "virtual power plant" fleet in August and September to coincide with CAISO flex alerts.

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2 Additional information *available at*: https://www.svcleanenergy.org/gridshift-ev/.
3 Additional information *available at*: https://sonomacleanpower.org/programs/gridsavvy.

Finally, in February of 2020, Clean Power Alliance of Southern California ("CPA") launched the "Power Response" programs that, among other initiatives, enable EV DR for commercial customers. The Power Response one-year pilot programs, operated in partnership with a leading DR provider (Olivine), also offer smart thermostat as well as solar/storage programs that serve residential customers, in addition to the solar/storage and EV charger demand reduction programs that benefit commercial and municipal customers.[4]

These are just a few examples of EV charging pilots and DR programs that are currently being operated by CCAs. However, there are many other programs that are currently operational or under development.[5] Further, as noted in the PD, CCAs also participated in the Joint Agency VGI Working Group, and contributed to the development of the "Final Report of the California Joint Agencies Vehicle-Grid Integration Working Group."[6] Finally, CCAs have also advocated in other proceedings in order to advance vehicle-to-grid ("V2G") use cases. For example, in the Self-Generation Incentive Program ("SGIP") proceeding, CCAs suggested that the Commission should create a new budget category to provide incentives for demand-managed EV charging, V2G and vehicle-to-building compatible EV supply equipment systems.[7]

B. The Joint CCAs Support the PD's Approach to Implementing Senate Bill 676 Reporting Requirements

The Joint CCAs recognize that Senate Bill ("SB") 676 established statutory reporting obligations for CCAs, and the Joint CCAs look forward to further collaborating with the

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4 Additional information *available at*: https://cleanpoweralliance.org/2020/02/19/clean-power-alliance-launches-new-smart-tech-programs-and-solarstorage-marketplace/.

5 For more examples, *see* VGI Working Group "Stock Take" for CCAs (developed June 2020), *available at:* https://gridworks.org/materials-produced-by-the-vgi-working-group-2/. *See also* Joint CCAs Opening Comments on Section 10 of the Transportation Electrification Framework, Appendix A: "CCA Transportation Electrification Initiatives: Examples of Existing Programs".

6 *See* PD at 4.

7 *See Opening Comments of the Joint CCAs in Response to Scoping Memo Questions* at 13, September 16, 2020, in Rulemaking 20-05-012.

Commission and the IOUs on VGI reporting matters. The Joint CCAs appreciate that the PD provides an appropriate amount of flexibility for CCA reporting, including allowing CCAs the ability to consult with Energy Division staff regarding reporting templates.[8]

At the same time, it is worth noting that activities associated with template development and reporting have the potential to be a significant administrative burden and cost on CCAs. This becomes potentially problematic and inequitable because of the different cost-recovery mechanisms used by IOUs, on the one hand, and CCAs, on the other hand. The Joint CCAs and Commission have previously identified this construct as an issue to be examined as greater emphasis is placed on advancing transportation electrification ("TE") programs.[9] The CCA business model is structured such that net revenue, after the purchase of electricity and administrative costs, is invested in rate stabilization, customer programs, and incentives that deliver community benefits. Thus, every dollar of generation rate revenue CCAs invest in reporting requirements is one less dollar available to support community investments.

The Joint CCAs acknowledge that the PD does not address the issue of "whether CCAs are eligible to apply to the Commission for TE program funding."[10] However, the Joint CCAs provide the foregoing as context to inform subsequent rulings regarding the role of CCAs in TE deployment. Moreover, the Joint CCAs encourage the Commission to recognize the need for allowing CCA TE programs, including those supporting VGI, to be funded via the same or similar sources as IOU programs, rather than just CCA generation rates.[11] The Joint CCAs note

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8 *See* PD at 60.

9 *See, e.g.,* Draft Transportation Electrification Framework at 132 "[a] significant difference between the CCA and IOU TE programs is the method for how the programs are funded. IOU program costs have largely been recovered through distribution rates. CCAs TE programs, on the other hand, are typically funded through their generation revenue. . ."

10 PD at 59.

11 *See* Joint CCAs Opening Comments on Section 10 of the Transportation Electrification Framework at 13-22.

that in other program areas, such as energy efficiency, CCAs are able to access common funding in order to support common reporting requirements.[12]

C. The Joint CCAs Request Clarification Regarding SB 676 Reporting Requirements

The Joint CCAs appreciate the Commission's acknowledgement that "[t]he Commission has not previously requested comments on how reporting requirements should be implemented by CCAs."[13] The Joint CCAs generally support the reporting approach described in the PD (namely, collaboration with, and agreement by Energy Division staff). However, additional clarifications are necessary to allow for further consideration of additional accommodations for CCA reporting requirements, consistent with other elements of the PD.

First, the Joint CCAs believe that clarification regarding the process for determining "relevant" reporting sections for CCAs is required. The PD states "each CCA shall report on its activities and programs using ***relevant*** sections of the reporting template developed for large electrical corporation reporting."[14] The PD also indicates that "[a] CCA may request the creation of a template for use by CCAs with the agreement of the Commission's Energy Division staff."[15] The Joint CCAs believe these two elements are related and should be treated similarly (through agreement with Energy Division staff). Therefore, the Joint CCAs request that the PD be modified to clarify that the sections of IOUs' templates that are considered "relevant" for CCAs should be determined at a later date through agreement between the CCAs and Energy Division staff.

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[12] *See e.g.,* Resolution E-5050 at 21(approving Redwood Coast Energy Authority's request for $47,250 during the three-year energy efficiency program to conduct process evaluations to qualitatively evaluate the program and market).

[13] PD at 59.

[14] PD at 59 (emphasis added).

[15] PD at 60.

Second, the PD indicates that "CCAs shall also provide outcome-based metrics related to their role providing energy . . . including but not limited to load profiles for EV charging and participation, CCA demand response programs, and avoided [greenhouse-gases ("GHG")]."[16] The Joint CCAs believe that CCAs should work with Energy Division to specifically determine what outcome-based metrics are most appropriate for CCAs to utilize. Therefore, the Joint CCAs request that the PD be modified to clarify that outcome-based metrics related to CCAs' "role providing energy" will also be determined at a later date through agreement with Energy Division staff. Additionally, "avoided GHG" as a metric also needs further clarification to ensure that all load-serving entities are utilizing the same GHG accounting methodology to determine the benefit of VGI programs.

The Joint CCAs believe that additional collaboration with CCAs will refine and improve the efficacy of these nascent CCA reporting requirements, and will allow reports to more fully serve their intended purpose without unduly burdening CCAs. A process that more clearly and fully allows for input from CCAs and approval by Energy Division staff will better achieve these objectives.

III. PROPOSED CHANGES

In accordance with Rule 14.3(c) and in light of the discussion above, the Joint CCAs request that the following changes be made to the PD (as shown in redline/track format with additions underlined):

Ordering Paragraph 17	Each of the Community Choice Aggregators (CCA) operating in utility territories subject to the Commission's jurisdiction shall describe how its current and planned activities (i.e. programs, rates, and investments in transportation electrification) are expected to further electric vehicle grid integration strategies. At a minimum, each CCA shall report on its activities and programs using relevant section(s) of the

[16] PD at 60.

	reporting template developed for large electrical corporation reporting. <u>Those sections of the large electrical corporation reporting template that are relevant for CCA reporting will be determined jointly by the CCAs and Energy Division staff.</u> A CCA may request the creation of a <u>separate</u> template for use by CCAs with the agreement of the Commission's Energy Division staff. Each CCA shall also provide outcome-based metrics related to its role providing energy, including but not limited to load profiles for electric vehicle charging and participation, CCA demand response programs, and avoided greenhouse gases. <u>Those specific outcome-based metrics that must be reported by the CCAs will be determined jointly by the CCAs and Energy Division staff.</u> CCAs may jointly report on any output metrics or other metrics with a large electrical corporation in their service territory. CCAs shall report by March 15, 2022 and annually through March 15, 2031.

IV. CONCLUSION

The Joint CCAs thank assigned Commissioner Rechtschaffen and Administrative Law Judges Goldberg and Doherty for their consideration of the comments provided herein.

Dated: December 3, 2020

Respectfully submitted,

/s/ Laura Fernandez

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December 3, 2019

Via Email and Regular Mail

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Re: Comments of the California Community Choice Association on Pacific Gas and Electric Company's Public Safety Power Shutoff Reports for the October 23, 2019 and October 26 and 29, 2019 consolidated events

Dear Ms. Malashenko:

In accordance with the reporting and commenting process established by the California Public Utilities Commission ("Commission") in Decision 19-05-042 ("PSPS Decision"), and the extension of the comment period to 25 days as authorized by the Executive Director on November 8, 2019 for PSPS post-event reports pertaining to events that occurred in October 2019, the California Community Choice Association ("CalCCA") submits the following comments on Pacific Gas and Electric Company's ("PG&E") *Public Safety Power Shutoff Reports to the CPUC* for both PG&E's October 23-25, 2019 PSPS event (the "October 23 Report") and PG&E's consolidated October 26 and October 29 PSPS events (the "October 26/29 Report") (jointly, the "Reports").

I. INTRODUCTION AND SUMMARY

CalCCA is the trade organization for the State's Community Choice Aggregation programs ("CCAs"). CalCCA's members are CCA programs that serve communities throughout California and encompass a significant number of the cities and counties impacted by PG&E's October 23-25, 2019 PSPS event (the "October 23 Event") and the consolidated events occurring on Oct 26 and October 29, 2019 (the "October 26/29 Events") (jointly, the "Events"). Many CCAs are located in high-fire risk areas (Tier-2 and Tier-3) with communities that have directly experienced the devastating impact of wildfires. CCAs are also critical partners in the Commission's efforts to address and combat the significant impacts of both wildfires and PSPS events.[1]

CalCCA recognizes that the respective Reports have different comment deadlines. However, many of the issues the addressed in these comments apply to both Events. This is due, in large part, to the immediate, back-to-back nature of the events. Although PG&E has reported the October 23 and the October 26/29 events separately, given the fact that the consolidated Events were separated by less than a day, the practical impacts of the Events are better viewed as a single, multi-stage event. This is reinforced by PG&E's decision to address consumer complaints regarding both the October 23 Event and the October 26/29 Events in the October 26 Report.[2]

1 *See i.e.*, D. 19-05-042 at p. 73 (defining CCAs as Public Safety Partners).
2 October 23 Report at 19 (Section 8 – Number and Nature of Complaints Received).

CalCCA strongly supports the Commission's proactive efforts to increase the safety of the investor-owned utilities' ("IOUs") distribution and transmission systems and thereby reduce the fire risk associated with operation of these systems. CalCCA recognizes that targeted PSPS events are part of these efforts. However, PG&E's October 23 and October 26/29 PSPS events (similar to PG&E's early-October PSPS events), provide an example of how PSPS events can be grossly mishandled. As clearly demonstrated in PG&E's Reports and discussed in detail below, PG&E's failures in the October 23 and 26/29 Events occurred at nearly every level.

In large part as a direct result of these failures, PG&E's October 23 and 26/29 Events had unprecedented impacts on public health and safety, particularly within low-income and highly vulnerable populations; and had substantial impacts on regional economies and the economy of the state as a whole. The Events strained local resources and subjected residents and businesses to the repeated trauma of power shutoffs, including uncertainty regarding their safety, economic wellbeing, and the availability of essential public services; and uncertainty regarding the reliability of electricity in the future. The extended PSPS Events resulted in inoperability of vital security, safety, health, and communications infrastructure equipment such as traffic lights, water/sewer pumps, natural gas supply, emergency alert system providers, gas stations, and cell towers. The flow of one event into another left some communities in PG&E territory without power for as long as 10 days. CalCCA agrees with the sentiment expressed by a large number of local government representatives and community members: the Events' duration and number of individuals affected by the Events were unprecedented, and taken together the Events are a corporation-induced disaster in and of themselves.

The Commission should reject any notion that PG&E is *unable* to do better. PG&E is a multi-billion dollar utility with over a century of operating experience, and PG&E has the resources and expertise to quickly implement a functional PSPS program *if doing so was in PG&E's interest*. The Commission must recognize that many of PG&E's failures are not the result of incompetence or the inordinate difficulty of creating a narrowly-tailored PSPS program with comprehensive mitigation measures. Instead, PG&E's failures are rational, strategic, and *intentional* responses to perverse incentives. When PG&E ignites a fire that causes billions of dollars in damage, it knows from the results of past wildfire litigation that it is very likely to be held financially accountable for this damage. On the other hand, when PG&E initiates a PSPS event that causes billions of dollars in disruption, economic losses, and harm to the public, there isn't a similarly established mechanism for holding PG&E financially accountable for these losses.[3] Thus, PG&E has an incentive to grossly overuse PSPS to avoid wildfire liability, as PG&E has not yet been held liable for the harm caused by PSPS outages. Put simply, as currently structured, PSPS allows PG&E to avoid wildfire liability while externalizing (and shifting to the public) the risks and costs of avoiding this liability.

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[3] At this time CalCCA does not take a position on whether existing laws, regulations, and policies provide adequate mechanisms for holding PG&E financially accountable for all harms caused by its PSPS outages. Rather, CalCCA notes that potential avenues of liability and recovery are not as clearly established as the existing avenues for the recovery of wildfire damages.

CalCCA appreciates that PG&E's Event Reports and the PSPS management practices described therein continue to evolve, and that the latest PSPS reports show incremental improvements to some aspects of PG&E's PSPS operations. However, the small progress demonstrated in the Reports only highlights the many miles to go before PG&E has a functional PSPS program that ensures that PSPS events are treated as a measure of last resort and are mitigated to the greatest extent possible.

Given the number, scale, and rapid succession of the PSPS events that have occurred in October and November 2019, many CCA programs and their communities are still gathering and analyzing the information regarding the adequacy and reasonableness of PG&E's actions during the collective Events. As such, these comments should be viewed as an initial, informal impression of the impacts of the Events on our communities. CalCCA and its members reserve their rights to raise additional facts and issues not covered in these comments in future Commission reviews of the Events, including those in the *Order Instituting Investigation Into The Late 2019 PSPS Events* (I.19-11-013) and the Commission's *Order to Show Cause* in the ongoing De-Energization Rulemaking (R.18-12-005).

II. BACKGROUND

On October 23, 2019, PG&E initiated a phased power shut-off that continued through October 25, 2019. This was immediately followed by a second power shut-off that began October 26, and a third shut-off that began on October 29. Power was not fully restored to all customers until November 1, 2019. PG&E notes that it staffed its Emergency Operations Center ("EOC") from October 20 to November 1, 2019 after identifying a developing series of conditions that could trigger PSPS events in Northern California, from the Coast to the Sierra Nevada. PG&E notes that the Events affected 177,000 and 941,000 customers, a number which requires clarification. PG&E's number reflects unique service points or accounts, not the actual number of Californians affected. The Events of late October 2019 affected in the vicinity of 2.3 million people.[4]

III. COMMENTS

On Wednesday October 23, 2019, PG&E called for a PSPS event after evaluating a series of weather events in Northern California that met PG&E's threshold for a power shutoff. Although it looked like the initial event would end on October 25, a second weather event triggered a second PSPS event starting on October 26, with further de-energizations occurring on October 29. For many electric customers in Northern California, the power came back on for a short period only to be turned off again a few hours later, while others did not have their power turned back on until October 30. These events, which affected more than 2.3 million people resulted in near-catastrophic impacts to affected communities and the State as a whole.

A. PG&E's PSPS Decision-Making Process Remains Grossly Unreasonable And Contrary To The Public Interest

In both Reports, PG&E provides a comprehensive overview of the factors that it considered when making the decision to call a PSPS event and make more granular de-energization decisions.

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[4] The Senate Energy, Utilities and Communications Commission received public comment where routinely speakers attributed a 2.5 per person count to each unique service point.

These factors that were considered in both the October 23 and October 26 PSPS decisions are as follows:

- Wildfire risk on each transmission line within the scope based on the forecasted windspeeds and Fire Potential Index as well as the structure type.
- Historical outage performance.
- Recent enhanced inspection information which resulted in approximately 67 lines determined to be at low risk.
- A Power Flow Analysis coordinated with the California Independent System Operator ("CAISO") which resulted in the addition of lines.[5]
- The risks posed by hazard trees that had been identified but not removed.
- PG&E's ability to reduce the number of lines to be de-energized through sectionalization.

In the both Reports, PG&E states that "in light of the meteorological information indicating the potential for catastrophic wildfire and the customer impacts from mitigating that risk through de-energization."[6] PG&E does not define or explain what it considers "customer impacts." Nowhere in the discussions of the Events does PG&E define or quantify the impacts to the customers and communities from de-energization. In previous Comments,[7] CalCCA and its members have documented a variety of risks and impacts that PG&E must identify, quantify, and weigh against wildfire risks before it can reasonably call a PSPS event. Troublingly, *none* of these impacts were included in PG&E's decision-making processes that led to its initiation of both events. CalCCA notes the following items that PG&E *did not* consider when deciding whether to call the PSPS events:

Table 1: Customer Impacts Considered In Decision-Making Process

Reasonably Foreseeable Impact	Considered by PG&E?
Overall economic harm (including lost productivity, spoilage, interrupted production, loss of worker wages, impacts to cell service and radio and television services, etc.).	No.
Additional costs to the State, cities, counties, tribes, and other public agencies.	No.
Impacts on economically disadvantaged individuals, families, and communities.	No.
Harm to small businesses.	No.

5 October 23 Report at 5; October 26/29 Report at 7.

6 October 23 at 6; October 26/29 Report at 7.

7 See *Comments of the California Community Choice Association on Pacific Gas and Electric Company's Public Safety Power Shutoff Report for the October 9-12, 2019 Consolidated Event*, at 5-6 and 8-10.

Interruption of education and impacts on schools / school districts.	No.
Risk of harm to increased risk individuals (including access and functional needs, medical baseline, and other individuals at an increased risk of harm during outages).	No.
Additional Safety Risk to the public at large.	No.
Impact on the operation of critical facilities and infrastructure.	No.
Psychological impact of uncertain availability of power and stress from repeated exposure to long-duration PSPS events.	No.

As CalCCA and its members have previously argued, for an IOU to be able to reasonably initiate a PSPS event, it must conduct an analysis that: 1) fully accounts for the reasonably foreseeable costs and impacts of de-energization and 2) weighs these costs and impacts against the likelihood and potential extent of wildfire harm avoided through de-energization.[8] Because PG&E did not fully consider and account for the potential harms of de-energization, its decisions to call the October 23 and October 26/29 PSPS events *were grossly unreasonable, especially given the massive scope and long duration of the power shutoffs*.

With regard to the Power Flow Analysis referenced by PG&E, the Commission should compel PG&E to provide this granular information to help inform communities regarding shut-offs in their areas. PG&E notes that based on the Power Flow analysis with CAISO, 13 additional lines were added to the October 26 Event, and 23 additional lines were added to the October 29 event. The scope of this Event exceeded 2.3 million impacted people. For both events, PG&E indicates that sectionalizing lines also reduced the number of accounts impacted and provides the number of service points removed from the scope of the PSPS event, but in both Reports PG&E fails to provide any further detail on this claim, including the number of outages prevented by sectionalization and the locations and identifications of the lines that were sectionalized.

PG&E notes that for the October 26/29 Event, risks included hazard trees that had been inspected but not yet removed.[9] For the October 23 Event, PG&E stated that 200 hazard trees still remained after mitigation efforts. No such numbers were provided for the October 26/29 Events, and PG&E's October 26/29 Report does not indicate how or if any of these earlier efforts to reduce vegetation impacts mitigated the October 26/29 Events.

8 *Id*.

9 October 26/29 Report at 7 (Table 1: Distribution Circuits De-Energized During October 26 and October 29 Events).

B. PG&E's Customer Impact Reporting Is Inadequate

i. PG&E's Reporting Of Event Time, Place, And Duration Is Inadequate

PG&E's description of the beginning and ending of the Oct. 23 Event does not match customer experience. By definition, an event ends when the last circuit is re-energized. In the October 23 Report, PG&E states that the Event ended on Oct. 25 at around 18:20, yet statements to the Senate Energy, Utilities and Communication Committee ("Senate Committee") establish that many areas remained without power either continuously from Oct. 23 to Nov. 1, or with only a brief window of only a few hours of service between the October 23 outage and the October 26/29 outages.[10] PG&E notes that it de-energized the first circuit in the October 26 event at 17:20. Based upon PG&E's PSPS Events reports,[11] customers should have had approximately 23 hours of power between events, but again, testimony to the Senate Committee echoed repeatedly that numerous customers in a variety of areas were without power for five, seven, or even up to 11 days.[12] Placer County Supervisor Cindy Gufstason reported that multiple communities in her district were without power continuously for up to seven days.[13] According to reports from the Placer County Office of Emergency Services, there were more than 5,000 service points that experienced extended outages.[14] As part of the Commission's further review of PG&E's PSPS events, PG&E should be compelled to provide accurate records of power outage and restoration, and also explain any disconnect between the records and customer experience.

ii. *PG&E Continues To Make Misleading Statements Regarding The Number Of Customers Impacted By Its PSPS Events*

In both reports, PG&E repeatedly makes references to the number of "customers" impacted by the PSPS events. These statements are highly misleading to the general public, as when PG&E speaks of "customers," it speaks of service points, not actual people. Thus, each residential "customer" is actually an address. The actual number of people impacted by an outage to each residential customer includes all individuals who live or work at that address. The numbers become confusing. In the Oct. 26 Event, PG&E notes 935,000 affected from the Oct. 26 shutoff and 596,000 in the Oct. 29 Event,[15] but then later says 941,217 distribution customers and 49 transmission customers were affected.[16] Using the larger numbers referenced in the Customer Impact section of the report, approximately 941,266 service points were impacted – residential, commercial, industrial, and agricultural. However, the number of people impacted (using the

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[10] Senate Energy, Utilities, and Communications Committee Meeting, November 18, 2019, Sacramento, Calif. https://www.senate.ca.gov/media/senate-energy-utilities-communications-committee-20191118/video

[11] October 23 Report at Appendix 1 (Table 1: Distribution Circuits De-Energized); October 26/29 Report at 7 (Table 1: Distribution Circuits De-Energized During October 26 and October 29 Events).

[12] Senate Energy, Utilities, and Communications Committee Meeting, November 18, 2019, Sacramento, Calif. https://www.senate.ca.gov/media/senate-energy-utilities-communications-committee-20191118/video

[13] Placer County Board of Supervisors Meeting, November 5, 2019. Meeting video available at: https://placer.granicus.com/MediaPlayer.php?clip_id=2517

[14] *Id.*

[15] October 26/29 Report at 7 (Table 1: Distribution Circuits De-Energized During October 26 and October 29 Events, at 7).

[16] October 26/29 Report at 9.

formula of 2.5 people per service point as consistently applied by a number of commenters during the recent Senate Committee hearing), PG&E affected 2.3 million people for 3 to 11 days, leaving them without power at their homes and/or workplaces. Most businesses rely on electricity and must close during outages. This results in extreme impacts to business owners in the form of lost revenue and damages to materials used for their businesses, and also extreme impacts to workers, particularly non-salaried workers who lose out on wages when their employers are closed.

PG&E's practice of referring to service points as "customers" is problematic, since in normal usage a "customer" generally refers to an individual person, not a household or a business address. In multiple reports on the October PSPS events, members of the media incorrectly conflated PG&E's references to the number of impacted "customers" as referring to the number of "persons" or "individuals" impacted by the outages. Thus, PG&E's use of the term "customers" creates confusion and misleads the public regarding the actual impact of PG&E's PSPS events. To prevent this issue in future PSPS events, CalCCA recommends that the Commission take the following steps:

1. Order that PG&E refrain from using the misleading term "customers" to refer to accounts or service points in all future PSPS-related communications with and notifications to the public, media, Public Safety Partners, government agencies, and other interested parties, and instead use the term "Accounts" to refer to accounts or service points impacted by a PSPS event, and the term "Individuals" to refer to the number of persons impacted by a PSPS event.

2. Require that in all PSPS notifications and communications in which PG&E references the number of accounts or service points impacted by a PSPS event, PG&E also provide the most accurate available estimate of the number of individuals that will be impacted by the event. The estimate should be based on household size data if such data is kept by PG&E. If PG&E does not have household size data, PG&E should develop the estimate using the most granular, accurate, and up-to-date information available, including, but not limited to, census data, and any more granular data that can be provided by state, county, city, and tribal governments.

3. Require that in all future PSPS Post-Event Reports, PG&E provide granular information regarding both the number of accounts / service points impacted by the outage and the total number of individuals impacted by the outage, along with a detailed description of how the number of individuals was calculated or estimated.

4. In Phase 2 of the De-Energization Rulemaking, adopt a comprehensive set of Commission-enforced rules governing IOU household size data collection and maintenance, and adopt a transparent and reasonable methodology for estimating or calculating the number of individuals to be impacted by a given PSPS event.

iii. *PG&E's Reporting of Customer Impacts Remains Grossly Inadequate*

In PSPS Post-Event Comments and in Comments in the De-Energization proceeding, CalCCA and others have repeatedly raised concerns regarding the adequacy of PG&E's consideration of customer impacts prior to calling PSPS events (as discussed above) and PG&E's

post-event efforts to assess and report the customer impacts of its outages. PG&E's Reports once again demonstrate its unwillingness to acknowledge the real-world harm created by its PSPS outages. In both Reports, PG&E's reporting on customer impacts is provided in the "Customers Impacted" section, and in both Reports, this section is limited to the following information:[17]

- Number of residential *accounts* de-energized.
- Number of commercial/industrial *accounts* de-energized.
- Number of "other" *accounts* de-energized.
- Out of the total number of accounts de-energized, the number that were medical baseline customers.

In addition, the October 23 Report, but not the October 26/29 Report, provides a regional breakdown of the number of customers de-energized.[18]

In its Reports, PG&E does not make any attempt to calculate or estimate the actual number of individuals impacted by the Events. In addition, PG&E's Reports fail to describe or quantify any of the following *actual impacts* experienced by its distribution customers and community members as a result of the events. While CalCCA, its member programs, and the communities they serve are still in the early stages of assessing the impacts of the Events, Table 2 (below) provides a partial list of some of the Events' negative impacts, along with some concrete examples of these impacts. None of the impacts listed in Table 2 were acknowledged or reported by PG&E as "Customer Impacts" in its Reports.

Table 2: Partial List Of PSPS Impacts With Illustrative Examples

Impact Type	Examples of Actual Impacts (October 23 and October 26, 2019 PSPS)
Overall economic harm (including lost productivity, spoilage, interrupted production, loss of worker wages, impacts to cell service and radio and television services, etc.).	Based on the Interruption Cost Estimator ("ICE") Calculator developed by the Department of Energy, The Lawrence Berkeley National Laboratory, and Nexant,[19] a one-day outage to 832,314 residential accounts and 108,903 non-residential accounts[20] in PG&E's service territory would result in $628.6 million in costs.[21] Again, this is for a single-day outage. Given the fact that most customers experienced multi-day outages, with some experiencing outages of almost 10 days, the actual overall economic impact of the Events is almost certainly in the multi-billions of dollars. During public comment on the PSPS events during the Placer County Board of Supervisors meeting Nov 5, 2019 Glen Ikeda of Ikeda's reported that the shutoffs

[17] October 23 Report at 8; October 26/29 Report at 9.

[18] October 23 Report at 8.

[19] Calculator available at: https://icecalculator.com/home

[20] Numbers taken from October 26/29 report at 9. Non-Residential accounts include accounts listed by PG&E as commercial/industrial and "other."

[21] This number is based on the following calculator inputs: State – "California." SAIDI – "279.1." SAIFI – "1.054." Both PG&E's SAIDI and its SAIFI values are actual index values for 2018 for PG&E's combined transmission and distribution system, including major outage events, taken from Table 2 (page 12) of PG&E's Annual Electric Reliability Report, available at: https://www.pge.com/pge_global /common/pdfs/outages/planning-and-preparedness/safety-and-preparedness/grid-reliability/electric-reliability-reports/AnnualElectricDistributionReliabilityReport2018.pdf

	resulted in 30 of his workers without wages, \$75,000 in lost revenue and \$16,000 in lost product.[22] At the same meeting, Colfax Mayor Joe Fatula reported that the already economically stressed community lost 6 to 7 days of power. The community has four internet providers, and two were down. The community has four cell service providers, and two were down. In addition, the communities hardlines were also down leaving thousands with any information. Further, Mayor Fatula emphasized the significant health and safety risk to a community where much of the housing was built between 1870 to 1940, so insulation is minimal. In cold weather, the internal and external temperatures equalize within a two-hours without heat maintenance. In addition, the majority of homes feature all electric configurations heating, water heating, and stove, and 60% were without wood heat. Mayor Fatula noted that evening temperatures in the area were in the 40s, leaving many of the elderly exposed to extended cold. As many of the people are employed locally, residents reported lost wages of up to ¼ of a month, and businesses lost perishables and revenue.[23]
Additional costs to the State, cities, counties, tribes, and other public agencies.	Sonoma County documented in the Senate Energy, Utilities and Communications oversight hearing (Oversight Hearing) on Oct. 18, 2019 hard costs, and soft costs such as opening, staffing and maintaining Emergency Operations Centers; calling out additional support for traffic management and other operations. Sonoma County reported in the Oversight Hearing as much as \$4.5 million in costs that must be covered but are not reimbursable from the state or other agencies.[24]
Impacts on economically disadvantaged individuals, families, and communities.	Although difficult to quantify based on currently available information, the PSPS events had significant impacts on economically disadvantaged individuals, families, and communities. These impacts include multiple days of lost wages due to workplaces being shut down, increased childcare costs/burdens due to school closures, and spoilage of frozen and refrigerated food and critical medicines.
Harm to small businesses.	One small business in Auburn reported to the Placer County Board of Supervisors that the PSPS event cost \$10,000 in spoilage and lost revenue of \$75,000.[25] Few small businesses can withstand these types of losses, especially when repeated in rapid succession.
Interruption of education and impacts on schools / school districts.	Schools are unable to safely operate without electricity and must be closed during PSPS events. This has a number of impacts. First, closing schools has a direct impact on students, who experience significant educational disruption, especially during multi-day outages. Second, closing schools has a direct financial impact on schools and school districts. California schools have daily attendance and instructional day requirements, and school funding is tied to per-student attendance. A method exists for applying for credit for lost attendance days when school is closed and lost attendance (lower

[22] Placer County Board of Supervisors Meeting, November 5, 2019. Video available at: https://placer.granicus.com/MediaPlayer.php?clip_id=2517

[23] *Id*.

[24] Senate Energy, Utilities, and Communications Committee Meeting, November 18, 2019, Sacramento, Calif. https://www.senate.ca.gov/media/senate-energy-utilities-communications-committee-20191118/video

[25] Placer County Board of Supervisors Meeting, November 5, 2019. Video available at: https://placer.granicus.com/MediaPlayer.php?clip_id=2517

	attendance than normal due to "events").[26] The Education Code provides a process for schools to apply for waivers for lost attendance and instructional days based upon certain criteria.[27] The California Department of Education has determined that the PSPS events for 2019 do fall under the definition of an emergency as an unanticipated situation and are subject to the waiver application process. An approved waiver avoids financial penalties for not meeting instructional day requirements upon audit. [28] According to California Department of Education, schools submitted more than 840 waiver applications for other emergencies during FY 2018/19 (due to floods, fires, earthquakes, evacuations, and other), so the PSPS is straining an already strained system, and the grant of waivers is not a certain matter. Third, closing schools creates a significant burden for families, particularly low-income families. For instance, working parents whose employers were still operational during the outages, faced a difficult choice – either miss work in order to watch their children, or take on the burden and cost of finding last-minute childcare during a massive power outage. Moreover, the closure of schools deprives many students of the nutritious meals they receive while attending school, a particularly significant problem for economically disadvantaged students who rely on school breakfast and lunch programs for food security.
Risk of harm to increased risk individuals (including access and functional needs, medical baseline, and other individuals at an increased risk of harm during outages).	Placer County Health and Human Services reported that while the emergency medical system did not experience significant medical surge issues due to PSPS events, home care and hospice systems were particularly impacted. Substantial efforts were made to ensure home care patients had the support and resources to remain in their homes and not need inpatient or emergency care. Skilled nursing facilities strained to provide routine care with the limited electricity provided by their own generators, particularly during back-to-back PSPS events. Prolonged periods without electricity increased the potential need to evacuate several skilled nursing and assisted living facilities. The Placer County Public Health Department monitored PG&E Community Resource Centers ("CRCs") for electricity-dependent medically fragile residents, which required substantial time and resources and the postponement of other public health efforts. The entirety of the PSPS experience demonstrated the resiliency of Placer County residents and the dedication of the health care agencies, but also revealed the vulnerability and dependence on access to consistent and reliable electricity. Prolonged PSPS events, long power restoration times, and inadequate CRC operational hours jeopardized the health and safety of medically vulnerable populations, putting most of the response burden on individuals, their support systems, health care agencies, and local government. The impacts on disabled individuals have been widely reported, and while consolidating the data will take time, the individual stories are harrowing. For instance, a wheelchair-bound 82 year-old resident of Marin County reported being trapped in an electric lift chair for 36 hours.[29]
Additional Safety Risks	Fire Chief Brian Estes reported to the Placer County Board of Supervisors on Nov. 5, 2019 that with the power off, the fire departments saw an uptick in the number of calls regarding fire threats involving the use of generators, increased calls due to the traffic light outage impacts. Estes also noted that Placer County area experienced a generalized increased anxiety in the population.

26 *See* https://www.cde.ca.gov/fg/aa/pa/j13a.asp

27 *See* https://www.cde.ca.gov/fg/aa/pa/j13a.asp and https://www.cde.ca.gov/fg/aa/pa/ma9001.asp

28 *See* https://www.cde.ca.gov/ls/ep/publicsafetyshutoff.asp

29 As reported at: https://www.huffpost.com/entry/california-fires-power-outages-seniors-disabilities_n_5dbb6039e4b0249f4821a289

	Placer County's Emergency Alert System was significantly impacted. KAHI radio is the local broadcasting station that has served the Placer and El Dorado communities for 60 years. KAHI lost power during the Oct 23-25 Event, and then limped along with a generator for a little while until the generator failed during the Oct. 26/29 Event. KAHI reported that they had no notice of the shutoff. Mike Remy, General Manager of KAHI Radio described the experience as, "Personal pleas to officials at the Gold Country Fair grounds to help us get power back were not heeded. Calls to media officials at PG&E were not returned. As an EAS station, we found ourselves dead in the water for a large majority of the blackouts. We ask, that in the future, the location of KAHI, Placer Counties' only radio station, be spared from the next outages."

PG&E's reporting of customer impacts needs to be expanded to include a thorough description and quantification of all significant PSPS-related impacts, including, but not limited to, the impacts discussed above.

Further, PG&E notes that the extended outages and staffing of its EOC contributed to fatigue in its staff and the need to train additional technical experts to provide certain specialized support during these events. In its comments on customer impacts, PG&E fails to consider that the same fatigue and resource depletion occurs at the local government level in County Offices of Emergency Services and the different departments (including local first responders) that those Offices activate to support a PSPS event.

C. PG&E's Notice And Communication Efforts Show Progress In Some Areas But Still Require Significant Improvement

i. PG&E's Notice To Vulnerable Customers Is Improving But Still Requires Significant Work

In Comments in Phase 2 of the De-Energization Rulemaking and its November 19, 2019 *Comments of the Community Choice Association on Pacific Gas and Electric Company's Public Safety Power Shutoff Report for the October 9-12, 2019 consolidated event*, CalCCA recommended that prior to each PSPS event, IOUs be required to make continuous efforts to notify each potentially impacted Increased Risk Individual ("IRI")[30] until the IOU receives confirmation that the IRI has been notified. CalCCA applauds PG&E for the initial progress towards this goal demonstrated in its Reports, but stresses that PG&E's notification process still requires significant expansion and refinement to ensure adequate notification of vulnerable populations.

In both Reports, PG&E states that it provided notice of the pending events to Medical Baseline customers according to the following protocol:

> For notifications during a PSPS event, medical baseline customers received automated calls, text and e-mails at the same intervals as the general customer notifications. In addition, these customers received repeat automated calls and texts at regular (hourly) intervals until the customer confirms receipt of the notifications by either answering the phone or responding to the text. If

[30] Defined as any individual at a significantly increased risk of harm due to a PSPS event, including individuals with serious medical conditions, access and functional needs individuals, individuals that rely on electricity-powered medical equipment, the elderly, and newborns.

> confirmation is not received, a PG&E representative visits the customer home to check on the customer (referred to as the "door knock process"). If the customer does not answer, a door hanger is left at the home. In both cases the notification is considered successful.[31]

CalCCA supports PG&E's focus on the need to continue notification efforts until confirmation is secured. That said, the protocol still clearly falls short in several areas. First, CalCCA is very concerned by the fact that PG&E's notice confirmation and door knock efforts are limited to enrolled medical baseline customers. Customers who happen to be enrolled in the Medical Baseline program represent only a subset of those customers who are at a significantly increased risk of harm during a PSPS event. Other groups of IRIs include access and functional needs individuals, the elderly and newborns, and individuals with serious medical conditions that are not enrolled in the Medical Baseline program.[32] PG&E must expand its confirmed notice and door knock program to provide notice to all IRIs, not just Medical Baseline enrollees.

Second, CalCCA is very concerned by PG&E's statement that it considers leaving a door hanger on a customer's door to be a "successful" notification of a pending de-energization. PG&E should be required to continue efforts to contact IRIs through calls, electronic communications, and multiple door knocks until confirmation is received. These efforts should continue even after power is shut off. If, after power is shut off, PG&E still hasn't received confirmation of notice from an IRI, PG&E should coordinate with local emergency services to continue attempting door-knocks and, if necessary, emergency services welfare checks.

ii. PG&E's General Notice To Customers Remains Inadequate

For both Events PG&E notes that it provided general notice to customers through media engagement and the PG&E website.[33] In addition, PG&E states that it provided notice to impacted customers through automated calls, texts, and e-mails. Many of the issues with communications have previously been documented, but the Events in late October demonstrated exacerbated customer notification issues. PG&E notes that for the Oct 23 Event, approximately 1,900 service points *were not notified* of the shut-offs because either there was no contact information on file, or the service point identification number was not mapped to the local transformer.[34] Additionally, Marin Clean Energy ("MCE") received numerous reports of customers being notified their power would be turned back on, 24 to 48 hours after the power had already been restored.

For the October 26 Event, PG&E notes that *28,600 customers did not receive advance notifications* and experienced outages of longer than five hours.[35] In addition to the reasons noted in the October 23 Event, PG&E reports that abnormal switching configurations had customers

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[31] October 23 Report at 15 (FN 9); October 26/29 Report at 13 (FN 18).

[32] This includes individuals with serious medical conditions that are not included in PG&E's Medical Baseline lists include individuals that don't qualify for the Medical Baseline program, individuals that have not heard of or do not fully understand the program, individuals who are newly diagnosed with serious conditions or haven't had the time to enroll, and non-English speakers with limited access to Medical Baseline information.

[33] October 23 Report at 13-14; October 26/29 Report at 11-12.

[34] October 23 Report at 16.

[35] October 26/29 Report at 14.

connected to one circuit, but their notification was based upon a normal circuit operation. PG&E also asserts that notification efforts were hampered by the challenge of reconciling customer mapping of the areas identified to be at risk to the assets on the grid, and then correctly identifying impacted customers. PG&E notes that these calculations are completed manually. Reliance on manual calculations for such a critical function is unacceptable. Manual calculations both slow down the process and introduce the risk of human error (especially with a fatigued staff). PG&E should be ordered to immediately implement an automated process for reconciling customer mapping and grid risk mapping, and share the results of this process with Public Safety Partners.

iii. PG&E's Notification and Communication With CCAs Remains Inadequate

In the PSPS context CCAs play multiple key roles. In these roles, CCAs need – and are entitled to broad – customer and outage information from the IOUs. As established by statute and relevant Commission Decisions, CCAs are entitled to any IOU-held information about customers within their service territories that they determine is relevant to the provision of CCA service.[36] As local government agencies (generally Joint Powers Authorities with boards comprised of elected leaders from the communities they serve), CCAs are entitled to all PSPS-related information that other public agencies, including cities, counties, and tribes are entitled to. As Public Safety Partners, CCAs are entitled to the mandatory disclosures that IOUs must make to such entities.[37]

To date, PG&E has fallen far short of meeting its information sharing obligation with the CCAs. The Reports fail to provide a detailed description of the required communications to CCAs. Instead, in both Reports, PG&E's reporting is limited to the general claim that it was in direct communication with telecommunications providers and CCAs throughout the events.[38] In neither report does PG&E acknowledge its obligations to provide notice to and share information with CCAs, and in neither report does PG&E provide anywhere near enough detail for the Commission to assess whether PG&E fulfilled these obligations.

PG&E's failures to meet its obligations to CCAs are clearly illustrated by MCE's experience during the Events. For both the October 23 and October 26 Events, MCE received customer lists only 24 hours ahead of the power shutoff. PG&E's unwillingness to share granular day-by-day and hour-by-hour outage data hampered MCE's ability to forecast its customer load. This was even more problematic during the October 26 Event, which involved widespread outages across MCE's service area that lasted for multiple days. MCE notes that information shared by PG&E such as total impacted customers per county is not very helpful for forecasting purposes and receiving impact information less than a day ahead of an outage is insufficient notice for day-ahead forecasting – particularly important for the large events impacting 2.3 million customers throughout PG&E's service territory. MCE further notes that all-clear notifications are less helpful for load management and could be improved if PG&E advised CCAs *by hour* who is on and who is still off. Re-energization needs to occur in in real time with clearer and faster communication

36 *See* Pub. Util. Code Section 366.2(c)(9); D.04-12-046 at 52-53; D.05-12-041 at 38-39.
37 D.19-05-042, *Appendix A: De-Energization (Public Safety Power Shutoff) Guidelines*, at A4, A15-A17.
38 October 26/29 Report at 12.

from the field to the EOC to the CCA. It would be ideal to receive 4-hour confidence intervals for impacted customers/circuits. CCAs could use information such as:

> 100% certainty that X circuit, serving Y customers, will be de-energized at 0800. 80% certain that X circuit will be de-energized at 1200, 40% certain that X circuit will be de-energized at 1600, etc.

This would not only be helpful for CCA load forecasting, but also for customers, small businesses, first responders, and local governments.

MCE also experienced inconsistency in information provided at the OES, local government briefings; either information is inconsistent or not the same type of information. Some information differed between PG&E representatives as well. MCE noted that information on the portal was not uploaded in a timely manner, and required an organization have someone monitor the portal for updates. Information was often received by other sources (i.e. media) before it was posted to the portal. In some instances, this inconsistency resulted in MCE staff hearing event updates in the media hours before hearing them from official PG&E or OES channels.

MCE reported that timing information during the "all-clear" and restoration stages was especially sparse. MCE also requests that post-PSPS, PG&E communicate information on a circuit / sub-circuit level, indicating when de-energization occurred, when "all clear" was declared, and when the circuit or sub-circuit was restored. This important information would help CCAs understand and anticipate PSPS timing and reduce uncertainty in future events.

MCE also noted that critical and essential accounts are no longer identified in the customer lists. In the first PSPS events, information was provided, but was confusing or conflicting. Some critical customers were identified, but others were not. For example, some wineries were included but small hospitals were not. The CCA experiences with the Events illustrates more strongly the need for PG&E to provide its definitions and procedures for determining "essential service" versus "critical facility," so that Public Safety Partners may help flag other necessary services such as emergency service alert radio stations and community centers.

iv. PG&E's Notification And Communication With Local Governments Remains Inadequate

In both Reports, PG&E's comments on communication basically summarize the number contacts made, then point to Appendices in both Event Reports documenting who was contacted and the time of the notification. The Report lacks an analysis or documentation of the effectiveness or quality of the communication. The automated notices, as described before, do not include the level of detail communities need to prepare. One of CalCCA's member programs, East Bay Community Energy ("EBCE"), in an effort to understand, evaluate and improve PSPS operations in its service area conducted a survey of several of its jurisdictions which include Alameda County and the cities of Albany, Berkeley, Dublin, Emeryville, Fremont, Hayward, Livermore, Oakland, Piedmont, San Leandro, and Union City. At the request of some jurisdictions, comments are provided without identifying attribution.

Notification

Jurisdiction 1:

Our city was shown in its entirety on the maps that went out Monday. The second set of maps only a portion included. The city was listed on each of the lists I saw put out by PG&E and Alameda County OES of affected cities, but it was NOT listed in Alameda County, it was listed in Contra Costa County (so was another city). This may be because we're connected to El Cerrito substations, but that's not an excuse for miscommunication – they needed to define it was a list by substation if that was the case. We were supposed to use their city portal, but that information was not clear either. We only got clear information late Tuesday night once we were able to connect with our PG&E representative (he was wonderful, and swamped), who initially shared that 2 commercial customers would be affected, and then later clarified they were cell towers. Then the actual power outage was much less than indicated on the maps, at least in the northern area, so all our warnings about nearby communities being impacted were incorrect.

Jurisdiction 2:

County Supervisors and most County staff received no prior warning of shut-offs beyond what the general public received; they learned about it along with their constituents; Supervisor received info from PG&E regarding which of the County's buildings would be affected; but the information was contradictory, confusing and last minute. It was difficult to get a straight or comprehensive answer as to which buildings would be affected. Numerous schools closed.

PG&E documents the number of meetings it had, the types of information it offered, and the calls it provided. These statistics illustrate the *quantity* of the communication, which could be said to voluminous. However, the *quality* of the information and timeliness left many local Public Safety Partners with challenges. Some jurisdictions reported that the placement of a PG&E liaison in a County EOC provided excellent access to information, while others reported that though they had a single point of contact, often that contact did not have as much information as was needed, current or requested by the local jurisdictions. Respondents further noted that the information frequently was not accurately representing the actual shut off activity in the community. PG&E noted that the dynamic nature of the weather events caused delays in information dissemination, most specifically for the Oct 26/29 Event. PG&E made a commitment to internally review the its processes to identify enhancements that may be necessary. Again, EBCE's jurisdictions provide insight into the experiences. The comments are unedited.

PG&E Briefings and Information

Jurisdiction 1:

There was frustration with the PG&E conference calls – they kept pushing the Monday morning call back because they didn't have information, their system was unable to mute people, at one point they kicked all cities off the calls, then after a backlash they let us back on. They didn't give the information we wanted on the calls because they truly didn't know. The County OES' conference line didn't have enough lines for multiple people per city so I got kicked off and had to rely on secondhand information, if I could get it.

Jurisdiction 2:
I would say that the information of what supposed to be impacted was clear in messaging via the PG&E maps, but the reality did not match up at all – The two small neighborhood areas shut off (which included City Hall and Police building) made no sense to me as why it was done this way – They are not contiguous parts of the City – In addition, we had some (but limited in number) traffic signals go down.

Jurisdiction 3:
The maps were vague and did not provide the ability to zoom into street level, so we were really still guessing what residents is was going to impact. We actually sent staff out to confirm outage area. One area that they said was going to be impacted was actually not.

Jurisdiction 4:
We participated in every PG&E "county" briefing, there were 3 phone calls a day. The information provided was helpful, but not enough. They were unwilling to address City specific questions or concerns…when I reached out to my assigned person…they were never able to provide me any more detailed information than what was given on the calls. Their conference call system was not able to handle the volume of calls and by the end they would only let one representative from each County OES ask questions…Cities had to feed their questions through their County OES. While I don't disagree with this protocol…it was not defined at the beginning….so people, including us were frustrated that we could not participate more fully.

<u>Community Impacts</u>

Jurisdiction 1:
We received a lot of calls (911, police, fire, public works, city hall, and myself all received calls) – eventually we set up a recorded message for people to be transferred to manage the call volume. The feedback we received was that people were confused about who would be affected and that there were rumors about potential water shortages. There was an expectation that the City should know and communicate EXACTLY the effects on the community, but we couldn't be certain and did not put a lot of trust in PG&E's maps so we wanted people to take the opportunity to be prepared for anything.

<u>Medical Baseline, Access and Functional Needs</u>

Jurisdiction 1:
Regarding the baseline customers. PG&E kept that list confidential and was responsible for contacting those individuals. It wasn't until the morning of the Shut-Off that they released the information to our fire department to contact the remaining baseline customers.

They provided the number of customers but were unable to tell us how many of our specific customers had been contacted by them via phone/door knocks. Our County did not sign the non-disclosure agreement so they would not release more detailed information to us. By the time they decided to release more detailed information to our County OES it was hours before the shut off and we never saw the information or have confirmation that our County actually received it.

Jurisdiction 2:
A Regional Social Service Center was shut off = massive inconvenience for people who rely on those services; Healthcare Services Agency -- according to OES--were staffed and prepared with lists of those who require medical services.

Additional comments and insights were included in the impacts on communities' chart above. The Joint CCAs would like to note that the Non-Disclosure Agreement continues to be an issue for local governments and CCAs. The Joint CCAs receive customer lists featuring customer name, service address, contact information, rate class category, and the circuit in numerical format (not in the format of the substation name with circuit number) as indicated in the report. This information is already included on the 4013's provided to CCAs for billing as it is their customers, and CCAs are subject to the Commission's Customer Privacy requirements. CalCCA continues to assert that CCA programs should be provided greater and more accurate customer information, system information, and PSPS outage information, as specifically requested by seven CCA programs in a letter to PG&E dated October 29, 2019.[39]

D. Damage To Overhead Facilities And Vegetation Management

In the October 23 Event report, PG&E notes that it recognized that there were 1,200 recently inspected trees that needed to be cleared prior to the event, with 200 remaining when the Oct. 23-25 Event began. PG&E does not identify the location of these trees in relationship to the areas that were damaged. The Safety and Enforcement Division ("SED") should request further detail on location and proximity of the removed to trees to the actual areas of damage PG&E reported. In addition, PG&E does not indicate where the remaining 200 trees were located nor does PG&E indicated in its inventory of damages if any of these pre-identified trees were actually responsible for the damages in either the October 23-25 or 26 & 29 Events, respectively.

The purpose of PSPS events is to prevent fires from igniting due to damaged utility infrastructure. Following the power shut off and the sounding of all clear, PG&E investigates its wires and poles to ensure it is safe to restore the power. In the Oct. 23 Event, PG&E noted that it inspected 7,800 miles of distribution and transmission circuits and found 26 instances of hazards. PG&E breaks these 3 categories: vegetation related damages; wind related or unknown damages, and hazards. PG&E refines the definitions noting that hazards include "things that could have sparked an ignition if the line was left energized such as a tree limb found suspended in electrical wires."[40] It should be noted 8 of the vegetation related damages were from fallen trees with actual

[39] Sonoma Clean Power Authority ("SCP"), MCE, Pioneer Community Energy ("Pioneer"), Valley Clean Energy ("VCE"), Redwood Coast Energy Authority ("RCEA"), Monterey Bay Community Power ("MBCP"), and EBCE.
[40] October 23 Report at 4.

equipment damage. Of the hazards 11 were branches or bark on conductors. What is not noted is any hardening information on the conductors or the true nature of the "hazard" risk.

For the October 26 Event, PG&E noted 328 instances of wind-related damage or hazards which included 212 instances of damage to PG&E's assets with 44 due to actual wind and 168 were due to vegetation damage. The other 116 instances included documented hazards. CalCCA notes that the listing by County and then transmission/distribution line permits easy review of the information, but it also raises questions about the efficacy of the PG&E vegetation management program. In many cases, the listed tree failures and damages to PG&E assets follow a specific line, perhaps indicating a metric that could be used to prioritize vegetation attention issues. For example, in Table 1 PG&E notes that Madera County San Joaquin #3 transmission/circuit line dominates the impacts for that county. Likewise, Bonnie Nook 1102 dominates the damage for Placer County, and Calistoga 1101 dominates Napa County damage. PG&E does not include within the report any indications of whether these were uninspected areas, areas slated to be tended or if they were previously unidentified issues under the vegetation management program.

Based upon PG&Es comments about identified tree hazards and the 1,200 addressed during the Oct. 23-25 event, and then the lack of specificity in the late Oct. 26 & 29 Event Report, CalCCA recommends that the SED request an analysis of PG&E's process for analyzing risks of vegetation along lines to be de-energized and the correlation to actual impacts and PG&E's already completed vegetation management. Questions to consider include:

- How many of these areas of damage occurred in locations that PG&E had already conducted recent vegetation management?
  - Many of these occurrences involved brush from outside of the vegetation management zone, indicating that perhaps the required minimum vegetation clearances should be expanded?
- How many were in areas of vegetation management yet to be completed?
  - How many were in areas crews had not reached yet?
  - How many of these were in areas crews had not been able to access and for what reason (private property with locked gates, threats from property owners, etc.?)

Further, CalCCA requests that the Commission request PG&E submit a vegetation management update for the counties explicitly documenting in what areas inspections have been completed (by percent or by map) and hazards documented (how many by category), what areas have had vegetation management efforts completed, what areas are still pending vegetation removal, and the timeline for the completion of that removal. The Joint CCAs recommend that the Commission request this analysis as part of its new *Order of Instituting Investigation Into The Late 2019 PSPS Events* (I.19-11-013) to examine:

- Is the vegetation management program going far enough?
- Do adjustments to the area of management need to be considered?
- Are there steps to take to help PG&E gain access to areas to remove vegetation threats?

E. Other Issues

i. *Complaints and Claims*

PG&E lists complaints for the latter October Events in the Oct 26 Report. PG&E claims 13 written complaints and 1 email. CalCCA questions how these complaint statistics are compiled and what metric PG&E uses to qualify a communication as a complaint. CalCCA knows that several of the jurisdictions in its members' service areas, both counties and cities, sent letters of complaint not only to the PG&E, but to the Governor's office and the President of the Commission. The documentation on the complaints in terms of customer class or category (i.e. city, business, resident) renders the information opaque.

For an event that impacted 2.3 million people, PG&E documents a few hundred financial claims for loss for both commercial and residential customers. What is unclear is how many these claims are unique. In addition, it is unclear what PG&E, or the Commission intends to deduce from the provision of these statistics. The messaging to customers has been that PG&E will not be reimbursing customers for losses due to PSPS. If the Commission is looking to better document losses, perhaps another approach is warranted.

ii. *Steps Taken To Restore Power*

CalCCA recognizes that PG&E thoroughly documents its re-energization process, including line inspection and repairs. CalCCA would like to see the discussion expanded to how this information is integrated into further hardening of the infrastructure or identification of additional vegetation management that needs to be completed as referenced in comments on the damage and types of damage found upon inspection.

iii. *Sectionalization*

CalCCA encourages further sectionalization and improvement of the PG&E infrastructure. Given the number, scale, and rapid succession of the PSPS events that have occurred in October and November 2019, many CCA programs and their communities are still gathering and analyzing the information regarding the adequacy and reasonableness of PG&E's actions during the collective Events. As such, these comments should be viewed as an initial, informal impression of the October 23-29, 2019 and October 26 & 29, 2019 events. With Commission's call for an *Order of Instituting Investigation Into The Late 2019 PSPS Events* (I.19-11-013) for the PG&E October Events and ongoing *De-Energization* proceeding (R.18-12-005), CalCCA and its members reserve their right to raise additional facts and issues not covered in these comments in those venues, including facts and issues relating to the reasonableness of PG&E's decision-making process and communications, and other actions related to all of the October to November 2019 PSPS Events.

iv. *Community Assistance Locations*

CalCCA refers the Commission to the comments from the City of Colfax which indicated that it needed support for its citizens. The CRCs were at least 15 miles away and provided charging stations, but were not *necessarily warming centers*. CalCCA encourages PG&E to continue to work closely with the local County OESs to ensure the unique requirements of communities are met.

v. *Lessons Learned From Events*

PG&E notes in the October 26 Event report that it is working on several items to improve the PSPS event information provided and management of the event.[41] Of these, strengthening of the day and external reporting notes a consistency issue in identifying areas via internal (Fire Index/Division) versus County and Tribal level. CalCCA encourages PG&E to initiate an education effort to explain its designations and references to local governments, and to go further by providing more detail on the substations and circuits in a community. These details would allow CCAs in collaboration with their communities, to evaluate areas where microgrids or backup generation could be deployed for maximum efficiency and community resilience.

In addition, PG&E notes that it deployed microgrids in some communities. CalCCA notes that this is also a lesson learned that PG&E should include in this section, along with a discussion of how the application of these types of resiliency measures may be expanded. CalCCA notes that CCAs are Public Safety *Partners* [emphasis added]. PG&E should work more closely and collaboratively with its partners to establish resiliency measures more quickly.

vi. *Proposed Updates to ESRB-8*

CalCCA acknowledges PG&E's intent to continue implementing ESRB-8 and reserves the right to comment further in Phase II of Rulemaking18-12-005 De-Energization.

vii. Other Relevant Information to Help the Commission Assessment of Reasonableness of Decision to Energize

CalCCA notes that in this section, PG&E reiterates much of its weather assessment and the use of the Operational Mesoscale Modeling System to provide outage percentage representing the historical frequency of hours that unplanned outage activity was observed at a given wind speed. PG&E notes that it applies this information to the PSPS weather models for its predictive approach. Included in PG&E discussion and descriptions of analysis are references to historic risk to specific lines and areas.

CalCCA asks that this type of historic modeling information be provided in detail for each of the affected areas so first responders, local governments, and Public Safety Partners may better understand and prepare for future events. In addition, as PG&E has this historical data available, it would appear that MCE's request for likelihood of a line shutoff, is not too far a reach. The Commission should direct that this information by transmission and distribution line be provide to local communities, noting that historical data indicates that during wind events of XX mph, line Y has Z percentage chance of outage.

IV. CONCLUSION

CalCCA thanks the Commission for its consideration of the points set forth in these comments. As stated above, these comments provide the CalCCA's initial thoughts and analysis

41 October 26/29 Report at 29-30.

of the October 9-12 PSPS, its impacts, and PG&E's Report, and CalCCA reserves the right to raise additional facts and issues regarding any of these subjects going forward.

Respectfully Submitted,

/s/ *Beth Vaughan*

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue the Development of Rates and Infrastructure for Vehicle Electrification.	)))))	Rulemaking 18-12-006

REPLY COMMENTS OF THE JOINT COMMUNITY CHOICE AGGREGATORS ON THE PROPOSED DECISION

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December 8, 2020

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

Order Instituting Rulemaking to Continue the Development of Rates and Infrastructure for Vehicle Electrification.	)))))	Rulemaking 18-12-006

REPLY COMMENTS OF THE JOINT COMMUNITY CHOICE AGGREGATORS ON THE PROPOSED DECISION

In accordance with Rule 14.3 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission"), the Joint Community Choice Aggregators ("Joint CCAs") submit these reply comments on the *Proposed Decision Concerning Implementation of Senate Bill 676 and Vehicle-To-Grid Integration Strategies,* dated November 13, 2020 ("PD").[1]

I. REPLY COMMENTS

A. The Joint CCAs Agree That CCAs Have "Separate and Distinct" Roles

In opening comments, Pacific Gas and Electric Company ("PG&E") noted "[t]he PD's proposed mandates to [Community Choice Aggregators ("CCAs")] should take into account their separate and distinct legal roles in [electric vehicle ("EV")] and [vehicle-grid integration ("VGI")] products and services."[2] The Joint CCAs agree. Unlike the investor-owned utilities ("IOUs"), CCAs do not own "make-ready" distribution infrastructure, such as transformers, panels, or wiring to parking spaces. Since CCAs do not own electric distribution infrastructure, certain elements of the reporting requirements may not apply to CCAs. However, while CCAs do

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[1] The Joint CCAs consist of Marin Clean Energy ("MCE"), Sonoma Clean Power Authority ("SCP"), California Choice Energy Authority ("CalChoice"), Silicon Valley Clean Energy Authority ("SVCE"), East Bay Community Energy ("EBCE"), Peninsula Clean Energy ("PCE") and the City of San José. The group of CCAs that comprises the Joint CCAs, as defined in this filing, is not identical to the group of CCAs that has filed under this designation in prior filings in this docket.

[2] PG&E Opening Comments at 14.

have a role that is separate and distinct from the IOUs, PG&E's further assertion that "vehicle-to-grid use cases are not applicable to CCAs" is incorrect, as further described below.[3]

B. VGI Use Cases Are Applicable to CCAs

While PG&E is correct that CCAs do not own, operate or invest in EV distribution infrastructure, the conclusion that vehicle-to-grid use cases are not applicable to CCAs is incorrect. There are many examples of VGI use cases that are applicable to CCAs, including customer bill management, managed charging, resiliency, and system greenhouse gas ("GHG") reductions. These use cases are not only applicable to CCAs, but are fundamental to the organizational mission of CCAs.

The fact that CCAs have already developed VGI-related pilots serves as clear evidence that VGI use cases are applicable to CCAs. As noted in the Joint CCAs opening comments on the PD, several CCAs have already developed managed charging pilots and/or demand response ("DR") programs for EVs.[4] These programs include SVCE's "GridShift: EV Charging" pilot, SCP's DR program, the GridSavvy Community, as well as Clean Power Alliance of Southern California's "Power Response" programs – each of which is an example of a VGI use case applicable to a CCA.[5]

From these programs, it is clear that VGI use cases are applicable to CCAs regardless of the ownership status of electric distribution infrastructure. In other words, CCAs do not need to own electric distribution infrastructure in order to develop programs that incentivize the end user and/or EV supply equipment ("EVSE") owner to participate in VGI initiatives that have been

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3 *See* PG&E's Opening Comments at 14.
4 *See* Joint CCAs Opening Comments at 2.
5 *See* Joint CCAs Opening Comments at 2-3.

developed by CCAs. Moreover, while CCAs do not own electric distribution infrastructure, CCAs own, operate, and invest in EVSE or charging stations. As noted in Attachment 1 of the Joint CCAs Opening Comments on Section 10 of the Transportation Electrification Framework, CCAs have co-funded (i.e., invested directly) in incentives for EV charging infrastructure via the California Electric Vehicle Infrastructure Project ("CALeVIP") or offered EV charger rebates directly.[6] For example, EBCE plans to make a significant co-funding commitment to CALeVIP. Moreover, some CCAs own and operate EVSE networks, including Redwood Coast Energy Authority, which started a pilot EVSE network in 2014 and currently operates and maintains 40 ports across 16 sites.

Finally, it is worth noting that the "Final Report of the California Joint Agencies Vehicle-Grid Integration Working Group" ("Final Report") also acknowledges that VGI use cases are applicable to CCAs. As noted in the Joint CCAs Opening Comments on the PD, CCAs participated in the Joint Agency VGI Working Group, and contributed to the development of the Final Report, which identified 320 "use cases" for VGI.[7] According to the Final Report, "CCAs participated actively in the Working Group, supporting the creation of recommendations for all Load Serving Entities. As nonprofit public entities governed by the cities, counties and towns that they serve, CCAs now represent a large driver of clean energy in California. As electricity suppliers to public sector, residential, business and industry customers, CCAs possess relevant customer data and are using that data to inform programs for transportation electrification. As CCAs continue to expand their transportation electrification programs, coordination and

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6 *See* Joint CCAs Opening Comments on Section 10 of the Transportation Electrification Framework (September 11, 2020), Attachment 1: "CCA Transportation Electrification Initiatives: Examples of Existing Programs."

7 *See* Final Report at 18, *available at* https://gridworks.org/wp-content/uploads/2020/09/GW_VehicleGrid-Integration-Working-Group.pdf.

planning between CCAs and IOUs on VGI will be essential."[8] The Final Report also defines "use case" and explicitly acknowledges that VGI use cases have value streams that flow to stakeholders such as CCAs.[9]

For all of these reasons, the Commission should reject PG&E's assertion that vehicle-to-grid use cases are not applicable to CCAs.

II. CONCLUSION

The Joint CCAs thank assigned Commissioner Rechtschaffen and Administrative Law Judges Goldberg and Doherty for their consideration of the comments provided herein.

Dated: December 8, 2020

Respectfully submitted,

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8 *See* Final Report at 14, *available at* https://gridworks.org/wp-content/uploads/2020/09/GW_VehicleGrid-Integration-Working-Group.pdf.

9 *See* Final Report at 56.

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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 ESTABLISHING PROCESS FOR BACKSTOP PROCUREMENT REQUIRED BY DECISION 19-11-016

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December 8, 2020

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OF THE STATE OF CALIFORNIA

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CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON THE PROPOSED DECISION ESTABLISHING PROCESS FOR BACKSTOP PROCUREMENT REQUIRED BY DECISION 19-11-016

The California Community Choice Association (CalCCA)[1] submit these reply comments pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure on the October 23, 2020 proposed *Decision Establishing Process for Backstop Procurement Required by Decision 19-11-016* (PD).

I. CLARIFY REQUIRED DOCUMENTATION FOR COMPLIANCE WITH MILESTONES AS DESCRIBED BY CLEANPOWERSF WITH SLIGHT MODIFICATION

In its Opening Comments, CleanPowerSF requests the PD be modified such that Load Serving Entities (LSE) with projects that have achieved commercial operation need only provide sufficient documentation to establish compliance with Milestone 3. CleanPowerSF also asserts that once compliance with Milestone 3 is confirmed, the LSE should not be required to make additional compliance demonstrations in future filings unless there has been a contractual change

[1] California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, CleanPowerSF, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, 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, Silicon Valley Clean Energy, Solana Energy Alliance, Sonoma Clean Power, Valley Clean Energy, and Western Community Energy.

or change in resource status that would justify a formal update to the Commission. Similarly, the American Wind Energy Association (AWEA-CA) notes that the PD requires the submission of documents containing significant sensitive contractual information without clearly articulated benefit.

CalCCA agrees with these suggested revisions but adds that LSEs establishing compliance with only Milestone 3 still be required to provide a declaration affirming the possession of the underlying contract(s) for the resource(s). This would both demonstrate that the resources are online and that the individual LSEs have the resources under contract. In addition to relieving the administrative burden on both the Commission and LSEs for online resources by only requiring documentation germane to determining compliance, this change would be consistent with the fact that Decision 19-11-016 acknowledges both new build resources and existing resources as incremental to the extent the resources are not on the baseline list.

II. 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 PD to limit the scope of documentation required to demonstrate compliance with procurement milestones.

Respectfully submitted,

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

Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Reliable Electric Service in California in the Event of an Extreme Weather Event in 2021.	R.20-11-003

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
REPLY COMMENTS ON ORDER INSTITUTING RULEMAKING**

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**BEFORE THE PUBLIC UTILITIES COMMISSION
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Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Reliable Electric Service in California in the Event of an Extreme Weather Event in 2021.	R.20-11-003

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION
REPLY COMMENTS ON ORDER INSTITUTING RULEMAKING**

The California Community Choice Association (CalCCA)[1] submit these reply comments in response to the *Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Reliable Electric Service in California in the Event of an Extreme Weather Event in 2021* (OIR), issued on November 20, 2020, pursuant to Rule 6.2 of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure and the directives provided by the OIR.

I. INTRODUCTION

CalCCA appreciates the myriad supply- and demand-side recommendations offered by stakeholders to shore up reliability on the California Independent System Operator (CAISO) controlled grid for Summer 2021. As the Commission observed, "...the OIR will only focus on those actions that the Commission can adopt by April 2021 and that the parties can implement

[1] California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, CleanPowerSF, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, 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, Silicon Valley Clean Energy, Solana Energy Alliance, Sonoma Clean Power, Valley Clean Energy, and Western Community Energy.

before the summer of 2021."[2] In the face of the wide range of possible solutions, Southern California Edison Company (SCE) best articulated a reasonable objective for this rulemaking:

> While SCE appreciates that the Commission is exploring all possible options to decrease demand and increase energy supply during peak demand and net peak demand hours, this effort will be better served focusing on options that can realistically and safely be operationalized within the next six months.[3]

With the extremely limited time available, CalCCA urges the Commission to take the following steps:

- ✓ Immediately set workshops beginning in early January to identify the extent of the Summer 2021 incremental need, leveraging existing analyses performed by the CAISO, SCE and other stakeholders;
- ✓ Recognize that directing procurement of *new*, currently unplanned resources for Summer 2021 is infeasible;
- ✓ Estimate the potential benefits from out-of-market solutions, which should be considered in evaluating the results of the needs analyses;
- ✓ Work with the CAISO toward temporary tariff modifications that will enable the CAISO to procure through its Capacity Procurement Mechanism (CPM) any available capacity needed to meet Summer 2021 requirements (1) to facilitate efficient and timely procurement; (2) to equitably share responsibility across all jurisdictional and non-jur(control; and (3) to minimize avoidable penalties on individual load-serving entities (LSEs) resulting from the scarcity of supply and constrained procurement periods; and
- ✓ Proceed expeditiously with its more holistic efforts in R.20-05-003 to ensure reliability through increased procurement.

CalCCA looks forward to working with the Commission, the CAISO and stakeholders to take these steps to ensure reliability for Summer 2021.

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2 OIR at 12.

3 Southern California Edison Company's (U 338-E) Comments on Order Instituting Rulemaking, Nov. 30, 2020 (SCE Comments) at 9.

II. REPLIES TO COMMENTS

1. Should the Commission consider directing the IOUs to design a new paid advertising program for distributing CAISO's Flex Alerts in various outlets, including social media? If so, how should the Commission authorize a budget dedicated to this purpose and what measures and budget level should be considered?

SCE supports enhanced customer communication during emergency events and funding to support further communication efforts,[4] while PG&E questions whether the Flex Alert program should be a CAISO function[5] and SDG&E raises reasonable concerns over equitable cost allocation.[6]

Moving the planning and administration of the Flex Alert program to the CAISO provides the most reasonable solution. This approach is, as PG&E points out, consistent with D.15-11-033[7] and would address the cost allocation issues raised by SDG&E. Flex Alerts benefit the entire CAISO-controlled grid, and the costs of providing this benefit should be borne equitably across all LSEs and their customers who rely on the grid, including non-jurisdictional LSEs. CAISO ownership also produces economies of scale by combining the budgeting, planning and administration by three investor-owned utilities (IOUs) into one process. While fully transitioning by Summer 2021 may be challenging and could be disruptive, the CAISO, the IOUs, and other LSEs should collaborate as closely as possible to ensure the benefits of Flex Alerts are maximized.

If the Commission rejects this approach and continues with funding support for the IOU program administration, it should expand funding to include community choice aggregators

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4 SCE Comments at 5-6.

5 *Opening Comments of Pacific Gas and Electric Company (39 E) on the Ordering Instituting Rulemaking,* Nov. 30, 2020 (PG&E Comments) at 4.

6 *San Diego Gas & Electric Company (U 992 E) Comments on Order Instituting Rulemaking,* Nov. 30, 2020 (SDG&E Comments) at 4.

7 PGE Comments at 4.

(CCAs). Both on their own initiative and at the request of the Governor's office, CCAs supported Flex Alert goals and amplified conservation messaging during the August emergency conditions. Thus, either individual budgets or coordinated program development with the IOUs would better enable CCAs to participate as full partners in the state's support for the Flex Alert tool.

3. Should the Commission explore potential options to encourage non-IOU LSEs to develop programs similar to CPP?

Like the three IOUs,[8] CalCCA supports the Commission's exploration of potential options to encourage non-IOU LSEs to develop Critical Peak Pricing (CPP) programs. CCAs have already begun to explore and, in the case of CleanPowerSF, have implemented their own similar CPP programs.[9] In line with UCAN's comments,[10] ensuring the adequacy of data provided to other LSEs is critical to the success of CPP programs administered by non-IOU LSEs. The Commission should direct each IOU to work with LSEs in their service territories to maximize the availability of comparable real-time data necessary to facilitate CPP programs.[11] As SDG&E points out, the need for other LSEs to develop these programs will become more and more critical as load migrates away from the IOUs.[12]

4. Should the Commission increase IOU marketing funds to increase enrollment in CPP or take other actions to increase customer participation in the program?

The Commission should not lightly take any requests for new or additional funding as the fiscal impacts of COVID-19 continue to impact ratepayers. Before undertaking this step, the Commission should ask the IOUs to take stock of their existing programs to assess whether

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8 SCE Comments at 6; PG&E Comments at 6; SDG&E Comments on Question 3.

9 *See* https://www.cleanpowersf.org/pdp.

10 Opening Comments of The Utility Consumers' Action Network (UCAN) to Order Instituting Rulemaking, November 30, 2020 (UCAN Comments) at 5.

11 UCAN Comments at 5-6.

12 SDG&E Comments on Question 3.

further benefits could be gained by enhancing communication with customers who are already enrolled or repurposing already authorized marketing funds. IOU commercial and industrial customers today generally default to CPP programs, and additional funding will not change their contribution. If the Commission nonetheless authorizes additional IOU funding, it must consider cost recovery for this funding. All LSEs should be treated similarly, ensuring that if the costs of the program are socialized broadly among customers, comparable funding is provided to CCAs implementing similar programs.

5. Should the Commission establish a new out-of-market and outside the RA framework emergency load reduction program (ELRP) that could be dispatched by CAISO/IOUs under specified conditions where participants are compensated only after the fact and based only on the amount of load reduction achieved during the dispatch window? If so, what are the key program design elements (e.g., dispatch conditions, compensation level, load reduction measurement considerations, target customer segments, etc.) that should be considered or incorporated? What other issues (such as interactions with existing supply-side and load-modifying programs) need to be considered in order to establish an ELRP? How should these issues be addressed?

Before establishing new out-of-market ELRPs, the Commission must allow the IOUs to implement currently planned programs[13] and develop timely pilots to test new ELRP concepts. SDG&E points out that it has a program available for Summer 2021 implementation, [14] and SCE contemplates potential limited pilot ELRPs.[15] To ensure that these programs provide actual benefits, however, it should direct that customers be compensated under these programs in proportion to their load reduction. It should also ensure equity in cost allocation; if IOUs are permitted to spread their costs across all customers, any other LSE operating a similar program should be granted similar funding opportunities.

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[13] SDG&E highlights its Emergency Load Shed Pilot, which can be put in place for Summer 2021. SDG&E Comments on Question 5.

[14] SDG&E highlights its Emergency Load Shed Pilot, which can be put in place for Summer 2021. SDG&E Comments on Question 5.

[15] SCE Comments at 7-8; PG&E Comments at 7.

It is also important to observe that non-IOU programs may already exist. Sonoma Clean Power's GridSavvy demand response was effectively deployed and reduced SCP's needs during the August outages. The CPUC should consider emergency load reduction programs that non-IOU LSEs are already planning or implementing to ensure that those programs are coordinated with IOU programs, and that those customers would also be compensated based on their load reduction.

6. ***Should the Commission allow BTM hybrid-solar-plus storage assets to participate and discharge their available capacity in excess of onsite load (and thus export to the grid) and receive compensation for the load reduction, including exported energy, under ELRP? Should this capability be expanded to include BTM stand-alone storage as well? Are there any Rule 21 or safety and reliability considerations that need to be addressed to permit storage, with or without NEM pairing, to export energy while participating in the ELRP? How should any safety and reliability issues be addressed?***

The IOUs raise concerns in response to this Question. SCE cites concerns about its IT system, safety, and "operational issues around incrementality, dual capacity, double payment, measurement, settlement, and verification…."[16] PG&E cites similar concerns, as well as the need for additional "tools for visibility and control" and CAISO and Federal Energy Regulatory Commission (FERC) approve for the export of market-integrated products.[17] SDG&E recommends addressing the issue in R.19-11-009 and R.19-09-009.[18]

CalCCA acknowledges that there are outstanding questions and barriers related to BTM integration under the current market structure. However, the existing tariffs and programs fail to allow BTM resources with exporting capabilities to fully use their potential or be fairly compensated for their services during reliability events. In this context, the Commission and CAISO should bear in mind that a wide range of analyses, including the Joint Agency's SB100

[16] SCE Comments at 9-10.
[17] PG&E Comments at 8.
[18] SDG&E Comments on Question 6.

modeling,[19] indicate that load management and BTM exports of all forms represent a major cost saving and reliability strategy that should be fully leveraged and fully valued. While adopting a methodology for assigning full capacity value to BTM hybrid and storage resources may not be settled before Summer 2021, CalCCA encourages the Commission to focus its near-term efforts on leveraging these resources through the ELRP to avoid stranding capacity that could otherwise contribute to grid reliability needs. Expanding ELRP to include net exported energy from BTM hybrids and storage resources offers a near-term, temporary solution to provide the appropriate incentives that leverage the flexibility and capabilities of these resources.

8. ***Should the Commission consider expedited procurement, including through the cost allocation mechanism for additional reliability procurement (e.g., expansion of existing gas-fired resources) that could be online for Summer 2021 and 2022? If so, how could this occur in order for the additional capacity to be online on time to address summer reliability needs. If not, why not?***

9. ***If the CEC, CAISO, or the CPUC conducts additional analyses regarding Summer 2021 load forecasts, should the Commission consider a mechanism to update RA requirements in April for the summer of 2021 or would it be appropriate for CAISO to use its capacity procurement mechanism (CPM) to procure additional capacity for the summer of 2021, should it be deemed necessary?***

PG&E reasonably points to the clear timing limitations on LSEs' ability to get new steel in the ground by Summer 2021.[20] SCE and SDG&E similarly focus on solutions that leverage existing resources and those new resources mandated by D.19-11-016.[21] CalCCA agrees with the IOUs that in terms of expedited procurement for 2021, the solution lies solely in maximizing the capacity of ***existing*** resources. Expedited procurement, potentially more focused on new resources, has also been taken up in R.20-05-003 in the context of the Staff Proposal on

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19 Draft 2021 SB 100 Joint Agency Report, Docket 19-SB-100 TN #: 235848.
20 PG&E Comments at 10.
21 SCE Comments at 12-13; SDG&E Comments on Question 8.

coordination between planning and procurement.[22] This approach requires the Commission and the CAISO to address several important issues:

a ***How much capacity is needed considering the capacity of all existing resources, imports, and resources developed in response to D.19-11-016?***

There are several different ways of assessing the incremental capacity need. The CAISO, through its stack analysis, suggests a need for 450-3,300 MW of incremental capacity.[23] SCE approaches the problem through a modified Loss of Load Expectation study, hinging results in part on the nature of the resources procured in response to D.19-11-016 and suggests that the procurement ordered in R.19-11-019 is adequate to maintain a Loss of Load Expectation of 0.09, assuming the entire capacity is energy storage successfully brought online by August 2021.[24] Stack analyses, while alone inadequate to pinpoint reliability needs, may also provide additional directional perspective on needed resources. However, developing a forecast of high enough quality to determine actual grid needs requires loss of load studies with adequate spatial and temporal resolution to capture critical dynamics, such as transmission constraints and energy needs outside of peak hours. The Commission should schedule three workshops beginning in early January to examine this issue and arrive, based on existing analyses and any other analyses offered by stakeholders, on a range of potential needs and expeditious and cost-effective solutions.

b ***How can any incremental needs be recognized in the existing RA and CAISO frameworks?***

If reasonable analysis demonstrates incremental need beyond 2021 RA requirements, as calculated using the current methodology, the Commission and the CAISO must determine how

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22 Staff proposal for procurement R.20-05-003.

23 CAISO Comments at 2-3.

24 SCE Comments at Appendix A.

to recognize that need in the current regulatory processes. Stakeholders offered a variety of proposals regarding how to proceed with the procurement of any needed incremental capacity. SDG&E suggests reviewing previously rejected bids.[25] PG&E urges the Commission to "place greater emphasis on demand-side solutions, such as demand response….."[26] SCE proposes allowing IOUs to execute bilateral contracts to expand the capacity of existing cost allocation mechanism (CAM) resources, with costs recovered through the CAM.[27] The CAISO urges the Commission to issue a procurement order for all LSEs as soon as possible[28] and to increase the RA requirements by applying a "temporary" Planning Reserve Margin (PRM) of 20 percent.[29] The CAISO also points to its ability to use backstop authority through its CPM.[30] CalCCA recommends the Commission and the CAISO to work together to rely first on the CPM process.

With roughly six months until Summer 2021 arrives, there is insufficient time to go through the process of increasing the PRM and allocating the increase among LSEs. This is particularly true given the desire to rely not only on peak load but a combination of peak and post-peak load. More importantly, increasing requirements and sending all LSEs out on a goose chase to hunt down the incremental capacity seems counterproductive and likely will only increase RA penalties with little purpose served.

Placing the procurement burden on the IOUs through the CAM is also inefficient. It would still require coordinated procurement among three IOUs, and the equities of allocating any need equally among the three IOU service territories is not apparent, particularly since the problem involves system, rather than local, reliability issues. Moreover, this approach fails to

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25 SDG&E Comments on Question 8.
26 PG&E Comments at 11.
27 SCE Comments at 13-14.
28 CAISO Comments at 8.
29 *Id.* at 11-12.
30 *Id.* at 11.

take into account the responsibilities of non-jurisdictional LSEs to share in the burden of augmenting system reliability resources.

The optimal approach would employ the CAISO CPM process. This approach centralizes the work of identifying, increasing the efficiency of the time-constrained process and contracting needed resources, including imports, and allocates responsibility equitably among all LSEs – both jurisdictional and non-jurisdictional. CalCCA acknowledges potential limitations of the CPM process, including its limitation to one-year contracts[31] and the uncertainty of how to implement the CPM as more of a "front stop" mechanism for limited Summer 2021 purposes. However, it seems much more efficient and likely effective for the CAISO to seek a temporary modification of its tariff to permit CPM contracts in excess of one year and to accommodate the use of the mechanism for this unusual "front stop" need for incremental procurement. The term of any commitments, however, should be limited as tightly as possible to avoid prolonging unnecessary reliance on natural gas resources into the future. CalCCA urges the CAISO to take these immediate steps, supported by the Commission and stakeholders, to quickly address potential incremental needs for Summer 2021.

These modifications would also need to consider the "trigger" for the incremental CPM procurement. While CalCCA does not support an increased PRM at this late stage a temporary PRM increase to facilitate deployment of the CPM for incremental procurement purposes could be a reasonable approach provided it is not applied in a manner that will place risk on individual LSEs for unnecessary non-compliance penalties. That increase, however, should *not* be set at an arbitrary level. Instead, the percentage should be set at a level reflecting the difference between

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31 CAISO Tariff §43A.3.1.

the actual anticipated requirements, determined as described in section a above, and the RA requirements allocated to LSEs based on the existing 15 percent PRM.

c ***How should out-of-market (OOM) resources, such as ELRP programs, be factored into the need determination?***

The Commission and the CAISO will likely not assign a Net Qualifying Capacity (NQC) to OOM resources, such as an ELRP. Indeed, the CAISO views ELRP resources as "'insurance value' beyond what is provided by resource adequacy."[32] The capability of these resources, however, should not be ignored in examining resources and need. CalCCA recommends that the Commission establish an estimated range of potential MW of OOM solutions and employ that value to determine where, in the range determined of incremental need determined as described in section a above, to set the temporary PRM increase.

d ***What opportunities exist to expand or increase output from existing resources in the short-run?***

To the extent there is clear, unmet need for Summer 2021 considering the existing resource fleet, the CAISO and/or other market participants may need to tap shut-in capacity and potential capacity enhancement opportunities.[33] The Commission should immediately request comments from parties with potentially responsive capacity to identify the range and timing of their solutions, which could include securing imports backed by firm transmission, maintaining resources at risk of retirement for additional time, etc. If a need is identified, bringing greater transparency to market options would benefit all market participants.

10. ***Should the Commission undertake a stack analysis of the amount of resources that would be necessary for summer of 2021?***

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[32] CAISO Comments at 7.
[33] Calpine, for example, identifies up to 100 MW of potential existing capacity. *Comments of Calpine Corporation on Order Instituting Rulemaking*, Nov. 30, 2020 at 1.

See response to Questions 8 and 9. The Commission should use a spatially and temporally explicit model to conduct a loss of load study, such as SCE's LOLE analysis, and any other analyses completed by stakeholders as the foundation for determining need through the workshop process.

11. ***Should the Commission consider requiring that load serving entities expedite the IRP procurement they have scheduled to come online? How would the Commission provide equitable incentives so that the expedited process does not disproportionately increase costs for that LSE? If so, please explain how this would work. If not, why not?***

Definitely not. During Summer 2020, Energy Division reached out to LSEs to identify opportunities to expedite procurement ordered under D.19-11-016. Unfortunately, project timelines, and, in particular, interconnection needs, severely limit the ability of LSEs and developers to shift development timelines at this late stage. Moreover, interconnection would be an insurmountable to be overcome in order to expedite IRP procurement. Finally, pushing timelines increases project costs with no guarantee of early completion. The Commission should instead work to clear any delays affecting D.19-11-016 compliance and focus more stridently on existing supply and load reductions.

12. ***Are there other opportunities for increasing supply for the summer of 2021 and/or reduce demand that the CPUC has not considered? If so, please provide details of these supply or demand resources and please explain how they can address reliability needs in the timeframe discussed in this OIR.***

Sonoma Clean Power Authority and Valley Clean Energy proposed Commission funding of a "rapid 20-day Potential Study to explore how a large-scale aggregated demand response program could meet a significant fraction of the needed capacity starting in 2021…."[34] The study would address three potential actions:[35]

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[34] *Opening Comments of Valley Clean Energy and Sonoma Clean Power Authority*, Nov. 30, 2020 at 2.

[35] *Id.* at 3.

- The new installation of automated demand response (ADR) controls on 200 MW of residential air conditioning loads in the Central Valley.
- The new installation of ADR controls on 200 MW of agricultural water pumping and refrigeration in the Central Valley.
- Changes to how existing utility demand response loads are dispatched that explore different dispatch times, frequency, and duration

Targeting Central Valley loads offers the potential to move the needle on demand response. CalCCA supports adoption and immediate implementation of this proposal.

CalCCA also encourages the Commission and the CAISO to review their import restrictions in the context of the lessons learned during the extreme emergency events. The recent regulatory turmoil around RA imports combined with the overly restrictive rules adopted by the Commission have already removed legitimate, resource-backed import supplies from the California market. While LSEs and import suppliers struggle to comply with the newly minted rules, CAISO has continued development of its own proposal, which is at odds with the Commission's approach. Aside from the confusion and potential for stranded assets caused by frequent drastic rule changes, CalCCA remains concerned that the CPUC and CAISO have gone too far. CCAs have been engaged in and support many elements of the CAISO's RA Enhancements initiative, however the proposed requirement for RA imports to hold firm transmission will remove available supply of reliable, deliverable import energy. More troubling, the requirement will enable the exercise of market power and increase costs without commensurately contributing to increased reliability for Californians. At a time when it is critical to secure agreements for dependable RA import resources, the rules being developed by the CAISO must strike the right balance of allowing legitimate imports to deliver to California without enforcing excessive requirements that cause harmful, unintended consequences.

17. ***Should the Commission explore short-term measures to expand electric vehicle (EV) participation in currently available DR programs (IOU DR, DRAM, non-IOU LSE DR)?***

While CalCCA strongly supports this direction, it may not be feasible in the short-term. Analysis could be undertaken, however, in the proposed study process discussed in response to Question 12.

III. CONCLUSION

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

Respectfully submitted,

Evelyn Kahl

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General Counsel to the
California Community Choice Association

December 10, 2020

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

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2021 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U 39 E)	Application No. 20-07-002 (Filed July 1, 2020) (Consolidated)
Expedited Application of Pacific Gas and Electric Company Under the Power Charge Indifference Adjustment Trigger. (U 39 E)	Application No. 20-09-014 (Filed September 28, 2020) (Consolidated)

OPENING COMMENTS OF THE JOINT COMMUNITY CHOICE AGGREGATORS AND THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON THE PROPOSED DECISION OF ADMINISTRATIVE LAW JUDGE WANG

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December 11, 2020

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OPENING COMMENTS OF THE JOINT COMMUNITY CHOICE AGGREGATORS AND THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON THE PROPOSED DECISION OF ADMINISTRATIVE LAW JUDGE WANG

Pursuant to Rule 14.3 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission" or "CPUC"), Central Coast Community Energy, CleanPowerSF,[1] East Bay Community Energy ("EBCE"), Marin Clean Energy ("MCE"), Peninsula Clean Energy Authority, Pioneer Community Energy, San José Clean Energy, Silicon Valley Clean Energy Authority, Sonoma Clean Power, and Valley Clean Energy Alliance (collectively the "Joint CCAs" or "JCCAs") and the California Community Choice Association,[2] ("CalCCA" and collectively with the JCCAs, the "CCA Parties") hereby submit these Opening Comments on Administrative Law Judge Wang's ("ALJ") December 4, 2020, Proposed Decision ("PD") regarding the above-captioned *Application of Pacific Gas and Electric Company ("PG&E") for Adoption of Electric Revenue Requirements and Rates Associated with its 2021 Energy Resource Recovery Account ("ERRA") and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation* ("ERRA Forecast Application") and the *Expedited Application of Pacific Gas and Electric Company Under the Power Charge Indifference Adjustment ("PCIA") Trigger (U 39 E)* ("PCIA Trigger Application"). The CCA Parties are grateful for ALJ Wang and Commission staff's efforts in issuing a PD in such a short timeframe around the Thanksgiving holiday.

The CCA Parties request the Commission revise the PD either (1) to adopt the unopposed November 20 Settlement Agreement filed by PG&E, the Joint CCAs, The Utility Reform Network ("TURN"), and CalCCA ("Settlement"), or (2) to adopt rates that otherwise achieve the objectives of the Settlement. The Settlement is designed to smooth the volatility of the PCIA while transitioning to a more stable long-term PCIA framework *without* burdening bundled customers with additional responsibility to carry ongoing PCIA Undercollection Balancing Account ("PUBA") balances. Achievement of these objectives requires adoption of two key provisions:

- A 36-month amortization of the PCIA Trigger Application's revenue requirement via a PUBA Adder; and
- Inclusion of the "above-the-cap" portion of the 2021 PCIA revenue requirement as part of the 2021 PUBA Adder.

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1 CleanPowerSF is the CCA for the City and County of San Francisco ("San Francisco") operated by the San Francisco Public Utilities Commission; San Francisco is a party to this proceeding.

2 Pursuant to Rule 1.8(d) of the Commission's Rules of Practice and Procedure, the California Community Choice Association has authorized the Joint CCAs to file these Opening Comments on its behalf.

Both of these "smoothing" provisions are already included in the record in this proceeding[3] and, under Rule 14.1, can be adopted in response to these comments without the need to issue an alternate proposed decision.[4]

The smoothing provisions benefit both bundled and unbundled customers through reduced rate volatility. The approach mitigates the volatility on bundled generation rates resulting from the ups and downs of financing the PUBA undercollections. It benefits unbundled customers by smoothing fluctuations in PCIA rates both from year to year, and within a year, due to PUBA triggers. The Settlement achieves this smoothing effect and leaves bundled customers better off, *i.e.*, paying lower PCIA rates in 2021. The PD does not. The approach, similar to the approach articulated in the proposed decision in Southern California Edison ("SCE") ERRA forecast and PCIA trigger proceedings, A.20-07-004 and A.20-10-007 ("SCE Proposed Decision"), also addresses the concerns the PD raises regarding the PCIA rate increase cap.

The PD does not raise policy concerns about this approach but focuses on technical issues that needlessly obstruct mutually beneficial policy goals. Specifically, the PD identifies Settlement provisions that are outside the scope of this proceeding and questions "whether to alter the PCIA cap for 2021" is procedurally appropriate. Each of these issues can be addressed in ways that do not create barriers to achieving the Settlement's goals and design.

The Joint CCAs acknowledge that the settling parties' agreement to file a Petition for Modification ("PFM") of the cap-and-trigger mechanism in D.18-10-019 ("PFM Term") is outside of the scope of this case.[5] The settling parties did not anticipate that the Commission would take action on this term in the context of this proceeding but included the PFM Term to provide a full picture of their goal of evolving the PCIA to greater stability over a three-year period. Indeed, the Commission has admonished parties for *not* providing this full picture in prior decisions, and the Commission has

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[3] *See* Exh. JCCAs-17; A.20-07-002 and A.20-09-014, *Opening Brief of the Joint Community Choice Aggregators*, pp. 4-12 (Nov. 17, 2020) ("JCCAs' Trigger Opening Brief"); A.20-07-002 and A.20-09-014, *Joint Motion for Approval of Settlement Agreement of Pacific Gas And Electric Company (U 39 E), California Community Choice Association, Joint CCAs, and The Utility Reform Network*, pp. 1-12 and Attachment A (Nov. 20, 2020) ("Settlement Motion") (As explained herein, including the "above-the-cap" portion of the 2021 PCIA revenue requirement as part of the 2021 PUBA Adder has the same impact as Term 6 in Attachment A, p. 5).

[4] California Public Utilities Commission Rule 14.1 (stating "A substantive revision to a proposed decision or draft resolution is not an 'alternate proposed decision' or 'alternate draft resolution' if the revision does no more than make changes suggested in prior comments on the proposed decision or draft resolution, or in a prior alternate to the proposed decision or draft resolution.").

[5] Proposed Decision at 13.

adopted settlements in the past in which parties have committed to take actions in other proceedings. Accordingly, the PD's rejection of the Settlement on the basis of the PFM Term is arbitrary and inconsistent with its prior decisions, rulings and requests for settling parties.

Likewise, the Settlement's unfortunate choice of words regarding "waiving" the 2021 PCIA cap should not be used as a barrier to the important goals reflected in the Settlement's design. The question presented in these cases is how to harmonize Ordering Paragraphs ("OPs") 9 and 10 of D.18-10-019. OP 9 establishes a PCIA rate increase cap, and OP 10 establishes the PUBA trigger. The answer to this question is to set the base PCIA rate at the cap (giving effect to OP 9), and manage the PUBA balance via a surcharge (giving effect to OP 10). The PD itself creates a "rate adder" to the 2021 PCIA rate, which it concludes is "in compliance with all applicable rules, regulations, resolutions and decisions for all customer classes."[6] In the same way, the Settlement and its provisions would set the PCIA rate at the cap and set the surcharge at a level that would both address the existing PUBA undercollection and prevent further accumulations to the PUBA in 2021.

Reading D.18-10-019 to prohibit *any* increase above the cap for any reason would defeat the purpose of the trigger and undermine the PD's own conclusions. The cap cannot be viewed in isolation, but must be viewed as a part of an integrated mechanism that regulates volatility. The settling parties simply ask the Commission to use the tools created by D.18-10-019 to set rates and mitigate volatility.

Beyond the Settlement, the PD's analysis and conclusions regarding PG&E's Green Tariff Shared Renewables ("GTSR") and Enhanced Community Renewables ("ECR") rates contain both factual and legal errors, misreading D.15-01-051 and appearing to misunderstand the issues in controversy. The PD also will deny refunds owed to bundled customers that depart in 2021 related to financing of the PCIA Undercollection Balancing Account ("PUBA"), prioritizing PG&E's preferred accounting treatments over the just treatment of ratepayers.

The Joint CCAs recommend revisions to the PD's Findings of Fact, Conclusions of Law, and Ordering Paragraphs ("OPs") in Attachment A to remedy these issues and adopt the two settlement-related provisions discussed above.

Beyond these suggested changes, the PD comprehensively addresses the numerous components of this complex and compressed proceeding. The CCA Parties appreciate the PD's adoption of provisions intended to increase transparency and the PD's well-crafted solution to the issue of MCE and

[6] Proposed Decision at Finding of Fact 14.

EBCE's proposed disadvantaged community budgets in 2021.[7] The true-up approach will ensure timely cost recovery for those important programs while ensuring accurate tracking of the greenhouse gas-related program funds.

I. THE PD SHOULD BE REVISED TO AMORTIZE ONE-THIRD OF THE PUBA BALANCE AND THE "ABOVE-THE-CAP" PORTION OF THE PCIA REVENUE REQUIREMENT IN 2021.

The CCA Parties continue to support the terms of the Settlement and prefer that the PD be revised to adopt the Settlement in its entirety. For the reasons discussed in detail below, if the Commission opts not to adopt the Settlement, the CCA Parties respectfully request the Commission revise the PD to integrate the central provisions of the Settlement aimed to smooth PCIA rate volatility while transitioning to a more stable framework:

- A 36-month amortization of the PCIA Trigger Application's revenue requirement via a PUBA Adder; and
- Inclusion of the "above-the-cap" portion of the 2021 PCIA revenue requirement as part of the 2021 PUBA Adder.

The following table, calculated by PG&E, summarizes the revenue requirements for the PUBA Adder under the Joint CCAs' preferred outcome as compared to the PD:

[7] Proposed Decision at Finding of Fact 5, Conclusions of Law 3 and 4, and pp. 25-26.

Table 1: Summary of PCIA Departing Load Surchages Under PD Versus Preferred Outcome

Summary of PCIA Departed Load Surcharge Under Proposed Decision and Preferred Outcome/Settlement Proposal (*$ millions*)			
Year	**Balance**	**Proposed Decision**	**Preferred Outcome**
2021	2020 PUBA	$255.0 (100%)	$85.0 (33%)
	2021 PCIA above cap[1]	$0	$200.6 (100%)
2022	2020 PUBA	-	$85.0 (33%)
	2021 PUBA[1]	$200.6[2] (100%)	-
2023	2020 PUBA	-	$85.0 (33%)
TOTAL		**$455.6**	**$455.6**

Note 1: The "2021 PCIA above cap" and "2021 PUBA" reflect use of 2017 GRC (+ attrition) for January/February 2021 and recovery of CPUC-approved 2020 GRC Proceeding costs starting March 1, 2021.

Note 2: Amounts for 2021 assume similar treatment of year-end 2021 PUBA balance as in the PD (i.e., recovery amortized over 12 months in 2022).

No party to this proceeding opposed either the Settlement or provisions similar to these within the Settlement. Their adoption will convey the benefits of the Settlement to ratepayers even if the Commission rejects the settlement itself.

A. The Settlement Provisions Reduce Volatility Over the Next Three Years While the PD Exacerbates Volatility.

The settling parties entered into the Settlement to achieve a number of objectives, chief among them reducing volatility for PCIA rates due to the PUBA trigger mechanism adopted in D.18-10-019.[8] The key to reducing such volatility is to stop the growth of the PUBA balance that might cause another PUBA trigger in 2021 while simultaneously drawing down the existing 2020 PUBA balance. The Settlement's request to "waive the cap," while inartfully stated, reflected an intention to implement effective PCIA rates for 2021 that include the full 2021 PCIA revenue requirement in order to ensure there will be no PUBA trigger in 2021.[9]

As the PD recognizes,[10] its framework will almost certainly result in a PUBA trigger in 2021, which will increase rate volatility over the next three years as rates whipsaw to finance and then recover

8 *See* Settlement Motion at 6-7 and 9.
9 *See id*. at 6-7 and 9 and Attachment A, p. 5, Term 6.
10 Proposed Decision at 17-18.

various undercollections and overcollections. In contrast, the Settlement will smooth such volatility, as demonstrated in the Figures 1 and 2 below. Those figures show the impacts of PUBA triggers on both bundled (Figure 1) and unbundled (Figure 2) customers during 2021 to 2023.[11]

Figure 1: Volatility in Bundled Customers Average Generation Rates Under the PD Versus the Settlement

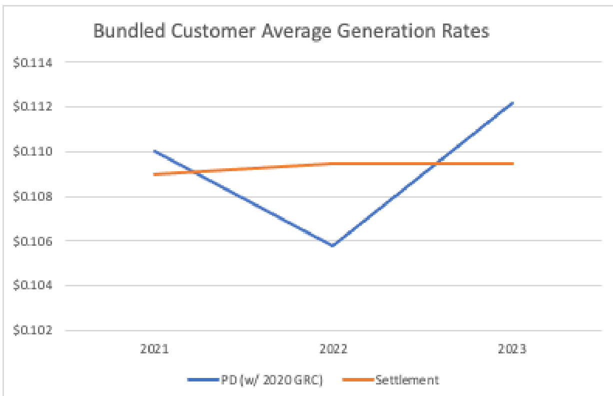
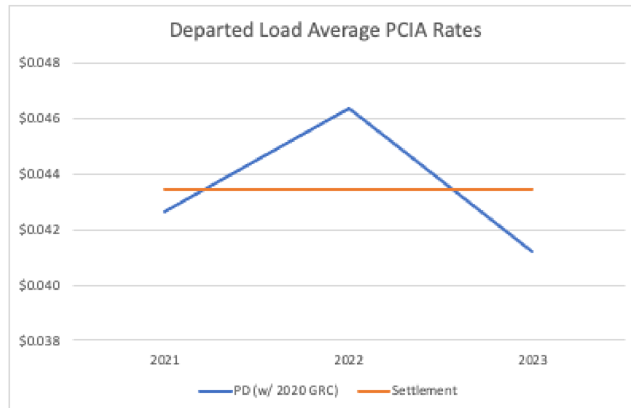


Figure 2: Volatility in Departed Load Average PCIA Rates Under the PD Versus the Settlement



As both figures show, *all* customers' rates remain more stable under the Settlement (orange line) versus the PD (blue line), holding all other factors equal.

B. Bundled Customers Will Pay Lower Rates in 2021 Under the Settlement Provisions Than Under the PD.

Also notable in Figures 1 and 2 is that once the 2020 General Rate Case ("GRC") rate increases take effect, the generation rates for bundled customers in 2021 will be higher under the PD (blue line) compared to the Settlement (orange line). The PD expresses a concern that "financing the PCIA cap is more burdensome for bundled service customers than it is beneficial for unbundled customers."[12] It further states that "the impacts of the bundled customers' financing of capped PCIA rates falls disproportionately on bundled customers in the Central Valley, who tend to have relatively higher electric bills and where a greater number of disadvantaged communities are located."[13] However, these problems persist *only* under the PD.

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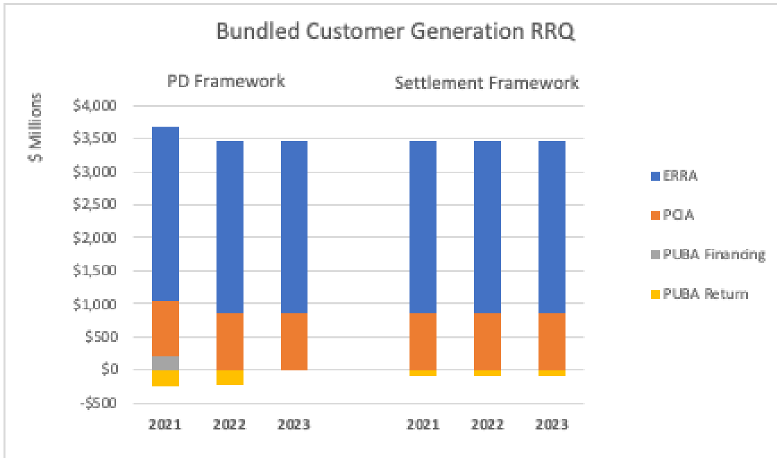
[11] Rates depicted in Figures 1 and 2 reflect the inclusion of PG&E's 2020 General Rate Case quantified in Appendix A to PG&E's November Update, as amended.

[12] Proposed Decision at 17.

[13] *Id*. at 17.

Figure 3 below shows how the PUBA financing (the gray box in Figure 3) that will result from the use of capped rates in 2021 will drive bundled customers' rates higher:

Figure 3: How PUBA Financing Drives Up Bundled Customer Rates in 2021 Under the PD



Stated another way, the bundled customers the PD seeks to protect are worse off under the PD than under the Settlement, which eliminates the cap and, thus, need for PUBA financing in 2021. As the Commission knows, all PG&E customers are facing imminent and substantial rate increases in 2021.[14] The PD should be modified to avoid adding PUBA financing to the burdens bundled customers will bear.

C. Rejecting the Settlement on Account of the PFM Term is Contrary to Numerous Prior Commission Decisions and Commission Policy on Settlements.

The Commission denies the Settlement for only two reasons, neither of which should prevent customers from realizing the benefits the settlement sought to impart on ratepayers. First, the PD denies the settlement motion because "the Commission cannot approve or deny the parties' agreement to jointly file a petition for modification; the parties simply file the petition."[15] However, these agreements to take action, or refrain from taking action, in other proceedings are not unusual in both settlements currently pending before the Commission,[16] or in Commission decisions adopting settlements. For example, D.20-02-016 and D.12-09-018 adopt settlements with terms to withdraw protests in a separate

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14 *See* PG&E Advice Letter 6004-E, *Annual Electric True-Up Submittal – Change to PG&E's Electric Rates on January 1, 2021*, p. 1 (Nov. 16, 2020).

15 Proposed Decision at 13.

16 *See, e.g.*, A.10-07-009/A.19-03-002, *Joint Motion of SDG&E, the Public Advocates Office, Utility Consumers' Action Network, Federal Executive Agencies, California Farm Bureau Federation, San Diego Airport Parking Company, Small Business Utility Advocates, Solar Energy Industries Association, Energy Producers and Users Coalition, California Large Energy Consumers Association, California City County Street Light Association, The Utility Reform Network, and the City of San Diego for Approval of the General Rate Case Phase 2 Settlement Agreement*, p. 10, section 10 (Oct. 8, 2020).

proceeding and require settling parties to support (or not object to) subsequent utility filings that may be made before FERC, respectively.[17] The PD's denial of the Settlement on account of a similar commitment to take a future action in another proceeding is arbitrary.

In D.17-07-005, the Commission admonished parties for not disclosing terms, similar to the PFM Term, included in a Memorandum of Understanding ("MOU") that was relevant to resolution of a PFM. The MOU contained, "in addition to the terms of the PFM agreed to by the parties", an agreement "to fund and implement an unrelated program intended to benefit low-income ratepayers."[18] Failing to disclose the MOU "undermined both the transparency of the PFM's potential effects and [the Commission's] ability to make a fully informed decision on the proposal."[19] In his concurrence, President Picker stated: "To avoid any damage to the integrity of the settlement process at the Commission, I think it is important that parties in future proceedings certify that all terms and consideration of any agreement are disclosed in the agreement."[20]

The CCA Parties acknowledge the agreement to file a PFM of D.18-10-019 is not within the scope of this proceeding since the PFM will be filed in R.17-06-026. However, including the PFM Term was necessary to provide a full picture of the settling parties' plan to propose evolution of the PCIA to greater stability over a three-year period and for the settling parties to agree to a future course of action. The PFM Term was not intended to bind the Commission's future actions or request the Commission prejudge the outcome of a future pleading. Its purpose was to ensure transparency to allow the Commission "to make a fully informed decision on the proposal."[21]

The Commission has a long-standing policy of supporting settlements.[22] Rejecting the Settlement on account of the PFM Term would set bad precedent restricting parties' ability to come to a

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17 D.20-02-016, Decision Adopting All-Party Settlement (Feb. 6, 2020) (2020 Cal. PUC Lexis 636) (Settlement agreement requires that, upon filing of the settlement agreement and approval by the Commission, parties agree to withdraw protests in related proceedings "and to support timely Commission approval of Crimson's application to acquire SPBPC under Application 19-04-008." (*21.)); D.12-09-018, Decision Adopting Settlement Agreement Revising Distribution Level Interconnection Rules and Regulations (Sept. 13, 2012) (2012 Cal. PUC Lexis 408) (Settlement Agreement may require certain approvals at FERC, and "Joint Settlement Parties agree to support, or not object to, these IOU filings at FERC." (*113)). *See also* D.20-05-019, Decision Approving Proposed Settlement Agreement with Modifications (May 7, 2020) (2020 Cal. PUC Lexis 662) (Term J: "The Settling Parties are prohibited from filing a petition for modification of a Commission decision approving this Settlement Agreement regarding any issue resolved in this Settlement Agreement." (*122.)).

18 D.17-07-005 at 6.

19 *Id*. at 2.

20 *Id*., Picker Concurrence, p. 3.

21 *Id*. at 2.

22 D.05-03-022 at 7-8; D.10-06-031 at 12.

compromise in proceedings such as the ERRA Forecast Application and PCIA Trigger Application that span multiple Commission programs and ratesetting mechanisms. The PD should be revised to avoid rejection of the Settlement on this basis.

D. The Commission Can Effectuate Full Benefits of the Settlement by Using the Flexible Tools Provided by D.18-10-019.

The second reason the PD denies the settlement is that it concludes the question of "whether to alter the PCIA cap for 2021 is outside the scope of this proceeding."[23] There can be no question the scope of this proceeding includes the setting of PCIA rates for 2021, including whether those rates are capped or uncapped. Three different scoping items in the ERRA Forecast Application address the PCIA, including scoping Item e., which asks whether PG&E's rate proposals should be adopted.[24] The scoping ruling in the PCIA Trigger Application asks whether PG&E's proposed "rate calculation methodology for determining the vintage specific PUBA rate adder to be applied *in addition to the authorized PCIA rates* for eligible departing load customers."[25] TURN, PG&E and the Joint CCAs' testimony, briefs and comments in both proceedings have extensively addressed PCIA rates in depth, including whether they should be capped or uncapped.[26] All interested parties in PG&E's service territory have had notice that the issue of whether 2021 PCIA rate increases will be permitted in excess of the \$0.005/kWh annual increase cap will be addressed in these proceedings, and no party has opposed the Settlement.

The CCA Parties understand the Commission's reservations about adopting a Settlement that would modify D.18-10-019 by eliminating the annual rate increase cap. The settling parties, however unfortunate their choice of language may have been, are not proposing such modification. The Settlement simply uses the tools provided by D.18-10-019 to achieve a beneficial policy outcome.

Using the PD's logic, the PD itself would modify D.18-10-019. The PD itself creates a "rate adder" to the 2021 PCIA rate, which it concludes is "in compliance with all applicable rules, regulations, resolutions and decisions for all customer classes."[27] The PD's rate adder, however, creates a PCIA rate increase, *i.e.*, an increase in the PCIA line item on each departed customer's bill, that exceeds the

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23 Proposed Decision at 13.
24 A.20-07-002, *Assigned Commissioner's Scoping Memo and Ruling*, p. 2 (Sept. 10, 2020).
25 A.20-07-002 and A.20-09-014, *Assigned Commissioner's Scoping Memo and Ruling*, p. 2 (Nov. 5, 2020) (emphasis added).
26 *See, e.g.,* Exh. PG&E-1 at 19-3:11 to 19:11-2; Exh. PG&E-6 at 21:1 to 27:15 and Appendix A; Exh. JCCAs-1 at 6, Table 3; Exh. JCCAs-17; JCCAs Trigger Opening Brief at 4-12; Settlment Motion at 1-12 and Attachment A; A.20-07-002, *Opening Brief of the Joint Community Choice Aggregators*, p. 5 (Oct. 30, 2020).
27 Proposed Decision, Finding of Fact 14 at 35.

$0.005/kWh cap set by D.18-10-019. Reading D.18-10-019 to prohibit *any* increase above the cap for any reason would override the PD and defeat the purpose of the trigger. The cap thus cannot be viewed in isolation, but as a part of an integrated mechanism aimed to balance PCIA rate volatility with the financing burden on bundled customers. The settlement parties are simply asking the Commission to use the tools created by D.18-10-019 to set rates and achieve these ends. Rather than exceeding the $0.005/kWh increase cap by the amount of the rate adder for the 2020 PUBA balance, as the PD proposes, the settling parties propose integrating what amounts to *the 2021* PUBA undercollection into that increase.

This approach is fully consistent with OPs 9 and 10 of D.18-10-019. OP 9 establishes the cap, and OP 10 establishes the trigger. The question presented here is how to harmonize those provisions. The answer is simple: set the base PCIA rate at the cap (giving effect to OP 9), and manage the PUBA balance via a surcharge (giving effect to OP 10). These are, in fact, exactly the mechanics the PD uses. In the *same way*, the Settlement and its provisions would set the PCIA rate at the cap and set the surcharge at a level that would both address the existing PUBA undercollection and prevent further accumulations to the PUBA (*i.e.*, at the uncapped rate) in 2021.

The SCE Proposed Decision similarly interprets D.18-10-019, recognizing the need to balance objectives in the interaction of the cap and the trigger. OP 6 of the SCE Proposed Decision proposes to:

> [A]pply a PCIA Trigger Mechanism Surcharge to departed load customers in 2021 which includes the following: 1) amortizes one-third of the 2020 year-end undercollection in the Portfolio Allocation Balancing Account Undercollection Balancing Account (PUBA) and [2)] the 2021 forecast PCIA Indifference Amount for departed load customers which exceeds the amount recoverable under capped PCIA rates. [28]

As the PD explains, the approach balances four competing interests: "1) minimizing rate shock for departed load customers, 2) providing fair returns to bundled service customers, 3) revising the PCIA rate to bring the PUBA balance below the PCIA trigger point, and 4) maintaining the PUBA balance below the trigger point until January 1 of the following year." [29] Adopting "a PCIA Trigger Mechanism Surcharge that includes the portion of the 2021 indifference amount which is above the 2021 capped PCIA rates" will maintain the PUBA balance below the PCIA trigger point.[30] This "adopted proposal

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[28] SCE Proposed Decision at Ordering Paragraph 6.
[29] *Id*. at 53.
[30] *Id*. at 54.

recovers this amount as part of the PCIA Trigger Mechanism Surcharge rather than waive or alter the PCIA rate cap requirement in D.18-10-019 for setting the 2021 forecast PCIA rates."[31]

In contrast, the PD will neither bring the PUBA balance below the PCIA trigger point nor maintain the PUBA balance below the trigger point until January 1 of the following year.[32] The PD clarifies that "the projected 2020 year-end PUBA balance addressed through a rate adder in this decision shall not be counted towards the requirement for PG&E to file a new expedited trigger application when the PUBA balance exceeds the trigger point."[33] However, as PG&E explained in record evidence,[34] there is only one PUBA, and while workpapers may be used to track the different balances for different years within the PUBA, the balance itself will remain above the trigger point if the PD is adopted, and it will stay above that point for most, if not all, of 2021 as the PD's 2021 PCIA rates add to the balance.

Regardless of terminology, the only way to stop the growth of the PUBA balance and draw down that balance is to set effective PCIA rates higher than the PCIA rate increase cap. The objective of overriding the cap in the way proposed by the Settlement was to avoid yet another mid-year 2021 PUBA trigger event, mitigate the uncertainty associated with the timing and amount of triggers, and avoid an unnecessary investment of the Commission and stakeholders' resources. The Commission can realize these benefits, abide by D.18-10-019, and ensure a consistent approach across the different utilities by revising the PD to adopt the approach in the SCE Proposed Decision.

E. The PD Results in Continued and Unnecessary Administrative Burdens.

As noted in the settlement motion, "the Settlement Agreement will avoid the need for PG&E to file a PUBA Trigger Application in 2021 and, depending on the Commission's decision on the contemplated PFM, in perpetuity. Avoiding the need for PUBA Trigger Applications in 2021 and beyond would significantly reduce the administrative and resource burden of the Settling Parties and the Commission in the coming years, promote rate stability, and save customers money in the process."[35]

Because the PD keeps the cap and trigger mechanism, these same parties, and the Commission, will need to relitigate these same issues in both a trigger proceeding next year and in the 2022 ERRA forecast proceeding. Such litigation will take place in the context of conflicting approaches to the trigger in both SCE and PG&E's service territories. The PD also jeopardizes an agreement to provide a

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[31] *Id*.
[32] D.18-10-019 at Ordering Paragraph 10.
[33] SCE Proposed Decision at 18.
[34] Exh. JCCAs-20.
[35] Settlement Motion at 10-11.

unified solution to the Commission regarding the cap and trigger mechanism across all three utilties' service territories within a Petition for Modification of D.18-10-019. In contrast, if the Commission revises the PD to adopt the approach in the SCE Proposed Decision, the remainder of the settling parties' commitments can be addressed separately by the parties as commitments to joint future action.[36]

II. THE PD ADOPTS A GTSR RATE THAT CLEARLY CONFLICTS WITH D.15-01-051.

The PD contains no reasoning on why it is implementing a GTSR rate for bundled customers that conflicts with D.15-01-051 and appears to misunderstand the issue. The Commission quotes the portion of that decision that supports *denying* PG&E's proposed GTSR rate because it requires matching the resources used to calculate the Resource Adequacy ("RA") charge for bundled customers to those "procured on their behalf."[37] It then notes the requirement that PG&E use the RA Adder to calculate the GTSR rate, which is not in controversy in this case—in fact, both PG&E *and* the Joint CCAs propose rate components based on the RA Adder market price benchmark used to calculate the PCIA rate.[38] This reasoning does not support a finding that the RA charge is "consistent with D.15-01-051" – it supports the opposite conclusion.[39]

The Joint CCAs agree with PG&E and the Commission that the RA Adder must be used when calculating the RA Charge.[40] The problem with PG&E's GTSR rate calculation is that it does not follow Finding of Fact 103 in D.15-01-051, which requires the RA Adder to be multiplied "by *the amount of RA procured on behalf of the GTSR customer*, assuming 15% reserve margin."[41] It also ignores the Conclusion of Law 52 and the statement that "[t]he utilities must charge all bundled customers, *including GTSR customers,* for the value of RA procured *on their behalf*."[42]

PG&E's methodology contravenes D.15-01-051 by calculating the GTSR RA charge from too broad of a pool of resources (in the numerator) and an even broader pool of customers (in the

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36 On pages 13-14, the PD misinterprets a provision regarding severability as applying to its ability to treat the settlement a set of stipulations. Rather, the purpose of that provision is to give parties flexibility in seeking to maintain their obligations if a settlement is rejected. That is the case here, where the joint advocacy on the PD by TURN, PG&E and the CCA Parties indicates a preference to keep the key provisions of the settlement in place even if the Commission does not adopt the Settlement.

37 Proposed Decision at 28.

38 *Id*.

39 *Id*. at 28, Conclusion of Law 7.

40 *See* Joint CCAs Opening Brief at 23-24.

41 D.15-01-051 at Findings of Fact 103 (emphasis added).

42 *Id*. at 105, Conclusion of Law 52 (stating "GTSR customer rates should require GTSR customers to be responsible for costs incurred on their behalf, including renewable integration costs, provided that the IOU does not already cover the cost through a different mechanism."); *see also* Exh. JCCAs-8.

denominator), creating a mismatch between the resources included in the calculation and the customers those resources serve.[43] The issue is that the RA Adder used in the PCIA rate is expressed in terms of "dollars per kilowatt per month" which is a charge incurred once each month, but the GTSR RA Adder is expressed in terms of "cents per kilowatt-hour" which is incorporated into the energy charge. Converting the units requires dividing the RA Adder by the applicable load. The language in D.15-01-051 quoted above specifies that this calculation use the capacity that serves only bundled customers, excluding any sales to any other customers such as LSEs serving departed customers, as the representative value of the capacity serving GTSR customers. Arriving at the value of the RA Adder to bundled customers on a cents per kilowatt-hour basis requires that the total value to bundled customers be divided by only the bundled customer load.

PG&E instead multiplies the RA Adder by the NQC of the *entire* PCIA-eligible generation resource portfolio, including Sold RA capacity that will be purchased by third-parties and even Unsold RA capacity that will neither be sold nor used on behalf of bundled customers.[44] That is, PG&E calculates the numerator using capacity that is not just procured on behalf of bundled customers, as required by D.15-01-051, but rather by using all PCIA-eligible capacity in the utility's portfolio, including the substantial amount of capacity PG&E sells to other load-serving entities.[45]

PG&E then calculates the denominator based on "bundled, CCA, and non-exempt direct access customers."[46] In order for "bundled customers, including GTSR customers" to be charged based on the RA capacity "procured on their behalf," the denominator should consist of only PG&E's bundled customers, including GTSR customers. Doing so ensures the customers in the denominator match the resources in the numerator.[47] The following table demonstrates the mismatched components of PG&E's proposed calculation and provides the alternative GTSR rate with all components properly corresponding to bundled customers.

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43 Exh. JCCAs-1 at 46:1-2.
44 *Id*. at 45:15-17.
45 *See id*.; *see also id*. at 19:3-12 (describing the difference between Retained, Sold and Unsold RA).
46 *See* Exh. JCCAs-12.
47 Exh. JCCAs-1 at 46:16-18.

Table 2: Summary of PCIA Departing Load Surchages Under PD Versus Preferred Outcome

Total RA, including Sold and Unsold RA

Retained RA Adder

Retained RA MW

	RA Adder	PG&E Proposal: Total RA Portfolio		Corrected: Retained RA	
	($/kW-month)	MW	$ Value	MW	$ Value
System RA	$6.10	3,336	$244,168	2,582	$189,003
Local RA	$6.15	5,474	$403,965	4,431	$327,000
Flex RA	$5.69	1,384	$94,499	785	$53,619
			$742,631		$569,622
Billing Determinants (MWh)			70,034,185		31,102,917
RA Charge ($/MWh)			**$10.60**		**$18.31**

PCIA-eligible MWh

Bundled Sales MWh

PG&E's approach contains a mismatch that directly contravenes the section of D.15-01-051 the PD cites because it mixes and matches different pools of resources and loads beyond those that are clearly identified as being attributable to bundled customers. The error requires the revisions to both the numerator and the denominator of PG&E's rate calculations the Joint CCAs proposed in this proceeding, resulting in an RA charge component of GTSR and ECR rates of $0.01831/kWh.[48]

III. THE PD DENIES FUNDS OWED TO CURRENTLY BUNDLED CUSTOMERS WITH NO PLAN TO PAY THEM BACK.

The PD's adoption of PG&E's proposal to return the PCIA Financing Subaccount ("PFS") to bundled customers via the ERRA rather than the PABA ensures funds owed to currently bundled customers will never be received. The PD's justification for this decision promotes PG&E's preferred accounting treatment over ratepayers, stating "Southern California Edison structured its financing subaccount differently than PG&E, and therefore it is reasonable for PG&E to have a different approach to returning balances to bundled customers."[49]

The PFS is used to track the amount financed by bundled customers related to the PUBA, that is, the revenue shortfall associated with capped PCIA rates for departing load customers.[50] The revenue deferral represents a credit owed to bundled customers that should be paid to those customers even if they depart.[51] Reimbursement to bundled customers for having financed the PUBA would take place via a reduction to future generation rates paid by bundled customers—same as an ERRA overcollection.[52]

48 Joint CCAs Comments on November Update at 8.
49 Proposed Decision at 21.
50 Exh. JCCAs-1 at 40:15-17.
51 Exh. JCCAs-1 at 41:8-11.
52 *Id.* at 41:11-13.

As such, it should be paid back in the same manner prescribed by D.20-02-047 for an ERRA overcollection, *i.e.*, "reflected in the PCIA rate" to ensure any overcollection credit benefits "all customers who paid into the overcollection."[53]

If the revenue deferral is effectuated only as a reduction to bundled rates, a customer who contributed to the revenue deferral prior to the PUBA Trigger Application, but then leaves bundled service, would no longer receive a credit or refund related to the revenue deferral.[54] PG&E has all but conceded this unfair treatment would occur.[55] Under the Joint CCAs' proposal, similar to the ERRA refund treatment discussed in the previous section, if the revenue deferral is transferred to the latest PABA vintage, customers would receive credit whether they remain bundled customers or choose to take unbundled service.[56] That is the approach followed by SCE,[57] and is the approach the PD should have required PG&E to follow here.

While the PD suggests this issue could be addressed in the PCIA rulemaking R.17-06-026, it will not be addressed in time to make whole those customers that depart in 2021 – if it is addressed at all. The PD should be revised to choose ratepayers over PG&E's preferred accounting treatment.

IV. CONCLUSION

Adopting the changes to the PD's Findings of Fact, Conclusions of law, and Ordering Paragraphs in Attachment A to these comments will prevent the errors of fact and law discussed herein.

Respectfully submitted,

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Counsel to the Joint CCAs

Dated: December 11, 2020

53 D.20-02-047 at 11.
54 Exh. JCCAs-1 at 41:17-20.
55 Joint CCAs Opening Brief at 17 (citing Exh. PG&E-4 at 22:16-18).
56 Exh. JCCAs-1 at 41:20 to 42:2.
57 Joint CCAs Opening Brief at 18-19.

ATTACHMENT A

Pursuant to Rule 14.3(b) of the Commission's Rules of Practice and Procedure, the CCA Parties offer the following index of recommended changes to the *DECISION ADOPTING PACIFIC GAS AND ELECTRIC COMPANY'S 2021 ENERGY RESOURCE RECOVERY ACCOUNT FORECAST, GENERATION NON-BYPASSABLE CHARGES FORECAST, GREENHOUSE GAS FORECAST REVENUE RETURN AND RECONCILIATION, AND RELATED CALCULATIONS AND RATE PROPOSALS*, including proposed changes to the Proposed Decision's Findings of Fact, Conclusions of Law and Ordering Paragraphs. The CCA Parties' proposed revisions appear in underline and strike-through.

Findings of Fact

10. Revising the resource adequacy charge component of PG&E's rate proposal for the Green Tariff Shared Renewables and Enhanced Community Renewables programs ~~is reasonable and in compliance with all applicable rules, regulations, resolutions and decisions~~ to $0.01831/kWh will ensure the resource adequacy charge reflects the amount of capacity procured on behalf of bundled customers participating in the program, as required by D.15-01-051.

14. ~~PG&E's proposal and methodology for the 2021 PUBA rate adder is reasonable and in compliance with all applicable rules, regulations, resolutions and decisions for all customer classes.~~ No party submitted comments on or opposed the terms of the November 20, 2020 settlement submitted by PG&E, CalCCA, the Joint CCAs and TURN (Settlement).

15. ~~PG&E estimates that the average rate impact of the proposed 2021 PUBA rate adder amortized over 12 months is 0.55 cents per kWh or 4 percent.~~ Setting a PUBA rate adder for departed load customers that amortizes the 2020 PUBA balance equally over three years (2021, 2022, and 2023) and includes the portion of the 2021 forecast PCIA revenue requirement for departed load customers that exceeds the amount recoverable under capped PCIA rates (1) is consistent with the terms of the Settlement and (2) will reduce rate volatility and increase affordability.

X. Requiring the revenue deferral related to the PUBA financing sub-account be transferred to the latest PABA vintage will ensure customers receive credit for funds owed to them whether they remain bundled customers or choose to take unbundled service.

Conclusions of Law

6. ~~The Commission should adopt~~ The resource adequacy charge component of PG&E's rate proposal for the Green Tariff Shared Renewables and Enhanced Community Renewables programs fails to follow D.15-01-051 and should be revised to $0.01831/kWh.

9. ~~PG&E's proposal and methodology to refund the entire 2020 PUBA balance to bundled service customers through generation rates and recover such amounts through a vintage-specific 2021 PUBA rate adder on top of PCIA rates with a 12-month amortization period is reasonable and should be approved.~~ Setting a PUBA rate adder for departed load customers that amortizes the 2020 PUBA balance equally over three years (2021, 2022, and 2023) and includes the portion of the 2021 forecast PCIA revenue requirement for departed load customers that exceeds the amount recoverable under capped PCIA rates is reasonable and in compliance with all applicable rules, regulations, resolutions and decisions for all customer classes.

~~10. The projected 2020 year-end PUBA balance addressed through a rate adder in this decision should not be counted towards the requirement for PG&E to file a new expedited trigger application when the PUBA balance exceeds the trigger point.~~

X. Requiring PG&E to transfer the revenue deferral related to the PUBA financing sub-account to the latest PABA vintage will ensure just treatment of all customers.

Ordering Paragraphs

1. This decision adopts and approves Pacific Gas and Electric Company's updated forecasts and requests as modified herein: (1) 2021 forecast of electric sales; (2) 2021 forecasted energy procurement revenue requirements; (3) 2021 Greenhouse Gas allowance revenue return forecast, clean energy program set asides and related costs; (4) 2021 Green Tariff Shared Renewables and Enhanced Community Renewables rate proposal; (5) proposal to credit vintage 2019 and vintage 2020 customers for Energy Resource Recovery Account overcollections; and (6) proposal to return the Power Charge Indifference Adjustment (PCIA) Undercollection Balancing Account (PUBA) balance to bundled customers through a rate adder to be applied in 2021 in addition to the authorized PCIA rates for eligible unbundled customers.

X. When calculating the 2021 rate adder for eligible unbundled customers in Ordering Paragraph 1, Pacific Gas and Electric Company shall include the following: 1) one-third of the 2020 year-end balance in the PUBA and 2) the portion of the 2021 forecast PCIA revenue requirement for departed load customers that exceeds the amount recoverable under capped PCIA rates.

December 15, 2020

Erik Jacobson, Director, Regulatory Relations
c/o Megan Lawson
Pacific Gas and Electric Company
77 Beale Street, Mail Code B13U
P.O. Box 770000
San Francisco, CA 94177

Re: Marin Clean Energy's Participation in PG&E's AMP

Dear Mr. Jacobson:

Pursuant to the request Pacific Gas and Electric ("PG&E") made in Advice Letter ("AL") 5943-E, Marin Clean Energy ("MCE") hereby provides notification of its intent to participate in the Arrearage Management Plan ("AMP").

If you have any questions, please contact me at (415) 464-6040 or sswaroop@mcecleanenergy.org.

Sincerely,

Shalini Swaroop
General Counsel and Director of Policy

Cc: Rene Mendoza
Service List for R.18-07-005

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Approval of Regionalization Proposal. (U39M)	)))))	Application 20-06-011 (Filed June 30, 2020)

WORKSHOP COMMENTS OF EAST BAY COMMUNITY ENERGY AND MARIN CLEAN ENERGY

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December 16, 2020

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Approval of Regionalization Proposal. (U39M)	Application 20-06-011 (Filed June 30, 2020)

WORKSHOP COMMENTS OF
EAST BAY COMMUNITY ENERGY AND MARIN CLEAN ENERGY

On November 20, 2020, the California Public Utilities Commission ("CPUC" or "Commission") held a workshop for parties to the above-captioned application to discuss PG&E's proposal for regional restructuring. In accordance with the schedule set forth in the *Assigned Commissioner's Scoping Memo and Ruling* in the instant proceeding, East Bay Community Energy ("EBCE")[1] and Marin Clean Energy ("MCE")[2] submit the following post-workshop comments.

[1] EBCE is a Joint Powers Authority formed on December 1, 2016 pursuant to California Government Code §§ 6500 et. seq. by the County of Alameda and each of the following cities incorporated therein: Albany, Berkeley, Dublin, Emeryville, Fremont, Hayward, Livermore, Oakland, Piedmont, San Leandro, and Union City. The Commission certified EBCE's Implementation Plan on November 8, 2017. EBCE started serving Alameda County businesses and municipalities in June 2018 and began serving residential customers in November 2018. On March 9, 2020, the Commission certified Addendum #1 to EBCE's Implementation Plan and Statement of Intent, adding the cities of Newark and Pleasanton, as well as the city of Tracy in San Joaquin County, to EBCE's service territory beginning in 2021. EBCE is currently one of the largest Community Choice Aggregators ("CCAs") in the state.
[2] MCE, California's first community choice aggregator ("CCA"), is a not-for-profit public agency that began service in 2010 with the goals of providing cleaner power at stable rates to its customers, reducing greenhouse emissions, and investing in energy programs that support communities' energy needs. MCE serves approximately 1,000 MW of peak load and provides generation services to more than 1.1 million people in 34 communities across Contra Costa, Marin, Napa, and Solano counties.

I. Introduction

EBCE and MCE appreciate the opportunity to provide feedback on PG&E's regional restructuring proposal, and strongly support the goal of making PG&E safer and more responsive to the needs of the communities it serves. However, additional information is required to ensure that the proposed regional restructuring is just, reasonable, and likely to achieve its stated goals. Critically, PG&E must provide additional information in its updated proposal about the budget and costs for its regionalization plan and for its core process improvements, in order to inform the Commission's cost-effectiveness analysis. Further, there are still several unanswered questions regarding operational and safety impacts, especially around decision-making, how competing priorities will be handled, and how CCAs and a more regionally-focused PG&E will coordinate to serve our shared customers. Finally, EBCE and MCE recommend that PG&E set forth a plan for soliciting stakeholder input in 2021 and 2022 on the initial stages of regionalization, if PG&E's plan is approved, to inform any future decision-making regarding additional functions under consideration for regional restructuring.

II. PG&E Must Provide Additional Information About its Regionalization Plan's Budget and Costs

EBCE and MCE share The Utility Reform Network ("TURN")'s concerns articulated at the November 20th workshop that PG&E has already begun to incur and record costs for regionalization but has not yet updated its cost forecast. It is important that the costs incurred provide ratepayer benefits that make the investment worthwhile. PG&E should provide more detailed budget information in its updated plan, including updating its budget forecast and delineating between its use of existing resources and its need for new and incremental resources such as personnel and facilities. EBCE and MCE agree with the California Large Energy

Consumers Association ("CLECA") that detailed information around where the existing service centers are, which personnel are located at each center, where new centers will be located, and how personnel will move around geographically will need to be provided in order for parties to understand which proposed costs are incremental to today's organizational structure. Furthermore, EBCE and MCE seek to better understand which costs are currently being considered incremental by PG&E and being recorded to the memorandum account.

PG&E's updated proposal should also include information about the costs for core process improvements. At the workshop, PG&E indicated that improving service will be in part based on improving four core processes: program management, asset management, work management, and customer experience. Are these core process improvements part of the regionalization plan or in addition to, and how do the costs of funding these improvements align with General Rate Case cost recovery and/or the plan's incremental budget?

PG&E should also provide additional details around the process for each region to receive its needed budgetary allocation. PG&E has indicated that budgets will not be implemented differently by the regions but determined centrally. How will budgets be set to accommodate regional needs and what is the interplay between the budget process and the decision-making authority of the regional vice presidents and regional safety officers? How will regional projects be prioritized?

Finally, it is important that any costs ultimately approved for recovery from ratepayers be cost-effective. PG&E must demonstrate in its update how the incremental costs it is recording and/or plans to record to the memorandum account are or will be cost-effective. This includes establishing metrics to measure whether the costs incurred actually improve safety performance. These metrics can be used to assess PG&E's future cost recovery request(s) related to its regionalization spend.

III. PG&E Must Provide Additional Detail Regarding the Operational and Safety Impacts of its Regionalization Proposal

EBCE and MCE appreciate PG&E's efforts to further clarify its proposal, but note that several key aspects of the application continue to lack the detail necessary to assess whether the regional restructuring proposal will improve operational and safety outcomes and responsiveness to local needs. The January revised proposal must address how priorities will be managed and disputes resolved under the proposed regional structure, provide additional detail regarding coordination between CCAs and PG&E and safety-related functions and decision-making, and set forth stakeholder engagement processes for any decisions to regionalize additional functions after 2022.

A. Prioritization and Dispute Resolution Under the Proposed Regional Structure

Under PG&E's proposed regional structure, functional operations will have a dotted line reporting relationship to the Regional Vice Presidents, while remaining centrally organized. This structure raises questions about how regional and central priorities will be balanced when they differ, and how disputes will be resolved. Regional Vice Presidents will be able to elevate local needs directly to the President, but the authority and resources to meet those needs will still need to come through PG&E's centralized decision-making, as they do today. In its updated proposal PG&E should provide clear insight into how decision-making at PG&E central will change in order to allow the restructured PG&E to better align with local agencies, communities, and needs.

B. Safety-Related Functions and Decision-Making

Under PG&E's proposal, Regional Safety Directors, wildfire safety functions, and electric distribution maintenance and construction will all have different direct lines of reporting.[3] Each of these roles and functions is essential to maintain a safe and reliable electric grid across all regions. In order to assess whether the regionalization proposal will improve PG&E's safety outcomes, PG&E must provide additional information regarding how the multiple actions, decisions, and functions related to safety will be allocated across these lines of reporting, and how the proposed scheme will improve safety outcomes. This includes, but must not be limited to, the functions central to PG&E's wildfire mitigation plan.

C. Coordination with CCAs in the Proposed Regional Structure

PG&E has noted that most of the functions that interact with CCAs will remain centralized,[4] but that community engagement and local customer engagement will become regional.[5] This raises questions regarding how coordination between PG&E and CCAs in the areas of customer and community engagement, and associated communications, will work under the proposed restructuring. PG&E notes that its enhanced coordination with local agencies will focus on wildfire planning and response, PSPS communication and coordination, resiliency planning, and community programs, among other issues.[6] EBCE and MCE also engage with our communities on these issues, both independently and in coordination with PG&E. In order to avoid customer confusion, it will be important for PG&E to continue to coordinate with CCAs as

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[3] Workshop Slide 29.
[4] Workshop Slide 32.
[5] Workshop Slide 29.
[6] Workshop Slide 32.

a part of these efforts, in particular regarding resiliency planning, PSPS communication and coordination, and wildfire planning and response.

IV. PG&E Should Provide Additional Information Regarding Stakeholder Engagement and Decision-Making Post-2022

PG&E notes that any decisions to further regionalize other functions will be informed by the results of its ongoing core process improvements, scheduled to be implemented through 2021 and 2022.[7] EBCE and MCE submit that any decisions to further regionalize additional functions must be informed by robust engagement of impacted communities, customers, and stakeholders. PG&E should include in its January update a plan for collecting robust feedback on the initial stages of its regionalization efforts, well in advance of any plans or decisions to further regionalize additional functions.

V. CONCLUSION

EBCE and MCE appreciate the opportunity to provide the above comments, and look forward to PG&E's updated proposal.

Dated: December 16, 2020

Respectfully submitted,

/s/ Stephanie Chen

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Counsel for
EAST BAY COMMUNITY ENERGY

[7] Workshop Slide 50.

December 17, 2020

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

MCE Supplemental Advice Letter 42-E-B

RE: Supplemental: Establish and Implement the Disadvantaged Communities Green Tariff Program Rate and the Community Solar Green Tariff Program Rate

Marin Clean Energy ("MCE") hereby submits this second supplemental advice letter ("AL") amending MCE AL 42-E that established and implemented the Disadvantaged Community Green Tariff ("DAC-GT") and the Community Solar Green Tariff ("CS-GT") programs, submitted on May 7, 2020.

TIER DESIGNATION

This supplemental AL has a Tier 3 designation pursuant to OP 17 of D.18-06-027.

EFFECTIVE DATE

Pursuant to General Order 96-B, this Tier 3 AL will become effective when the Commission adopts a resolution approving the advice letter.

BACKGROUND

On June 21, 2018, the California Public Utilities Commission ("Commission" or "CPUC") approved of D.18-06-027, adopting three new programs to promote the installation of renewable generation among residential customers in disadvantaged communities ("DAC"),[1] as directed by the California Legislature in Assembly Bill (AB) 327(Perea), Stats. 2013, ch 611. The three programs include the DAC Single Family Solar Homes ("DAC-SASH") program, which provides up-front incentives for the installation of solar at low-income homes in DACs. The other two programs, the DAC-GT and the CS-GT programs are community solar programs which offer 100% solar energy to customers and provide a 20% discount on the electric portion of the bill.

Pursuant to D.18-06-027, Community Choice Aggregators ("CCAs") may develop their own DAC-GT and CS-GT programs and must file a Tier 3 AL to propose implementation details ("Implementation AL").[2] MCE filed its Implementation AL for the DAC-GT and CS-GT programs

[1] DACs are defined under D.18-06-027 as communities that are identified in the CalEnviroScreen 3.0 as among the top 25 percent of census tracts statewide, plus the census tracts in the highest five percent of CalEnviroScreen's Pollution Burden that do not have an overall CalEnviroScreen score because of unreliable socioeconomic or health data.
[2] D.18-06-027, at p.104 (OP 17).

with the Commission in MCE AL 42-E on May 7, 2020. MCE also filed a Supplemental AL 42-E-A on October 16, 2020 to make two narrowly focused updates to the customer enrollment process under the DAC-GT program.

PURPOSE

MCE submits this second Supplemental AL to describe program capacity transfers between CCAs as authorized under Resolution E-4999. The resolution allows CCAs that serve customers in the same IOU service territory to share and/or trade program capacity.[3]

Since the filing of MCE's original Implementation AL, some CCAs in PG&E's service territory have elected to not pursue one or both of the DAC-GT and CS-GT programs and to forego their capacity allocations per Resolution E-4999.[4] These non-participating CCAs have elected to transfer their allocations to the participating CCAs in PG&E's service territory. The involved CCAs, both participating and non-participating, have agreed to distribute the transferred capacity in equal parts among the participating CCAs and have signed a joint letter of support to that effect. The letter is attached to this filing as Appendix B. As confirmed in an email with Energy Division staff on November 25, 2020, this letter is being submitted as an alternative to, and in lieu of, the CCAs implicated by this proposal submitting separate written comments in response to the CCAs' ALs.

Capacity Transfer under the DAC-GT Program

Sonoma Clean Power ("SCP"), Central Coast Community Energy ("3CE"), formerly known as Monterey Bay Community Power, and Silicon Valley Clean Energy ("SVCE") have determined to not implement the DAC-GT program and to trade their program capacity to the participating CCAs in equal parts.[5] The CCAs that will implement the DAC-GT program include East Bay Community Energy ("EBCE"), Clean Power San Francisco ("CPSF"), MCE, Peninsula Clean Energy Authority ("PCE") and San Jose Clean Energy ("SJCE"). The following table shows the assigned program capacity for each of the non-participating CCAs per table 1 in Resolution E-4999, as well as the capacity being transferred to each participating CCA.

Transferring CCA	Capacity being Transferred (MW)	Receiving CCAs				
		EBCE	CPSF	MCE	PCE	SJCE
SVCE	0.5	0.100	0.100	0.100	0.100	0.100
SCP	0.5	0.100	0.100	0.100	0.100	0.100
3CE	0.68	0.136	0.136	0.136	0.136	0.136
TOTAL	**1.68**	**0.336**	**0.336**	**0.336**	**0.336**	**0.336**

[3] Resolution E-4999 at 16 and 54 (Findings and Conclusions 17)
[4] Id, at 14
[5] Valley Clean Energy Authority has also chosen to not implement the DAC-GT program but was not included in the capacity transfer process due to its negligible program capacity allocation.

As seen in this table, the capacity transfer under the DAC-GT program results in an increase of 0.336 MW for each participating CCA. Added to MCE's original program capacity of 4.31 MW, this leads to a total program capacity of 4.646 MW for MCE under the DAC-GT program.

Capacity Transfer under the CS-GT Program

SCP, 3CE, SVCE, and SJCE have determined to not implement the CS-GT program and to trade their program capacity to the participating CCAs in equal parts. The CCAs that will implement the CS-GT program include EBCE, CPSF, MCE, and PCE. The following table shows the assigned program capacity for each of the non-participating CCAs per table 1 in Resolution E-4999, as well as the capacity being transferred to each participating CCA.

Transferring CCA	Capacity being Transferred (MW)	Receiving CCA			
		EBCE	**CPSF**	**MCE**	**PCE**
SJCE	0.36	0.0900	0.0900	0.0900	0.0900
SVCE	0.09	0.0225	0.0225	0.0225	0.0225
SCP	0.06	0.0150	0.0150	0.0150	0.0150
3CE	0.18	0.0450	0.0450	0.0450	0.0450
TOTAL	**0.69**	**0.1725**	**0.1725**	**0.1725**	**0.1725**

As seen in this table, the capacity transfer under the CS-GT program results in an increase of 0.1725 MW for each participating CCA. Added to MCE's original program capacity of 1.11 MW, this leads to a total program capacity of 1.2825 MW for MCE under the CS-GT program.

MCE submits an updated Implementation Plan (in redline) as Appendix A to this AL to reflect the corrected total program capacities for both the DAC-GT and CS-GT programs.

CONCLUSION

MCE respectfully requests the Commission approve the modified implementation details proposed by MCE in this supplemental AL.

NOTICE

A copy of this AL is being served on the official Commission service lists for Rulemaking R.14-07-002.
For changes to this service lists, please contact the Commission's Process Office at (415) 703-2021 or by electronic mail at Process_Office@cpuc.ca.gov.

PROTESTS

MCE respectfully requests that the Commission maintain the original protest period designated in MCE AL 42-E pursuant to GO 96-B, General Rule 7.5.1, and not reopen the protest period.

CORRESPONDENCE

For questions, please contact Jana Kopyciok-Lande at (415) 464-6044 or by electronic mail at jkopyciok-lande@mceCleanEnergy.org.

/s/ Jana Kopyciok-Lande

Jana Kopyciok-Lande
Senior Policy Analyst
MARIN CLEAN ENERGY

cc: Service List: R.14-07-002

California Public Utilities Commission

ADVICE LETTER SUMMARY

ENERGY UTILITY

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

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

Utility type:

- [x] ELC
- [ ] GAS
- [ ] WATER
- [ ] PLC
- [ ] HEAT

Contact Person: Jana Kopyciok-Lande
Phone #: 415-464-6044
E-mail: jkopyciok-lande@mcecleanenergy.org
E-mail Disposition Notice to: jkopyciok-lande@mcecleanenergy.org

EXPLANATION OF UTILITY TYPE

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

(Date Submitted / Received Stamp by CPUC)

Advice Letter (AL) #: 42-E-B

Tier Designation: 3

Subject of AL: MCE Supplemental Advice Letter 42-E-B

Keywords (choose from CPUC listing):

AL Type: [ ] Monthly [ ] Quarterly [ ] Annual [ ] One-Time [x] Other:

If AL submitted in compliance with a Commission order, indicate relevant Decision/Resolution #:
D.18-06-027 and Resolution E-4999

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

Summarize differences between the AL and the prior withdrawn or rejected AL:

Confidential treatment requested? [ ] Yes [x] No

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

Resolution required? [x] Yes [ ] No

Requested effective date:

No. of tariff sheets:

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

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

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

Tariff schedules affected: N/A

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

Pending advice letters that revise the same tariff sheets: MCE AL 42-E and MCE AL 42-E-A

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

Clear Form

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

CPUC, Energy Division Attention: Tariff Unit 505 Van Ness Avenue San Francisco, CA 94102 Email: EDTariffUnit@cpuc.ca.gov	Name: Jana Kopyciok-Lande Title: Senior Policy Analyst Utility Name: Marin Clean Energy Address: 1125 Tamalpais Ave City: San Rafael State: California Zip: 94901 Telephone (xxx) xxx-xxxx: 415-464-6044 Facsimile (xxx) xxx-xxxx: Email: jkopyciok-lande@mcecleanenergy.org
	Name: Heather Shepard Title: Director of Public Affairs Utility Name: Marin Clean Energy Address: 1125 Tamalpais Ave City: San Rafael State: California Zip: 94901 Telephone (xxx) xxx-xxxx: 415-46406024 Facsimile (xxx) xxx-xxxx: Email: hshepard@mcecleanenergy.org

Clear Form

ENERGY Advice Letter Keywords

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

Clear Form

APPENDIX A

Implementation Plan for the Disadvantaged Communities Green Tariff and Community Solar Green Tariff Programs

Proposed by Marin Clean Energy

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December 17, 2020~~December 2, 2020~~

TABLE OF CONTENTS

1. INTRODUCTION

In June 2018, the California Public Utilities Commission (CPUC or Commission) issued Decision (D.) 18-06-027, creating three new programs to promote the installation of renewable generation among residential customers in disadvantaged communities (DACs). The three programs include the DAC Single Family Solar Homes (DAC-SASH) program, which provides up-front incentives for the installation of solar at low-income homes in DACs. The other two programs, the DAC Green Tariff (DAC-GT) and the Community Solar Green Tariff (CS-GT) programs are community solar programs which offer 100% solar energy to customers and provide a 20% discount on the electric portion of the bill.

The DAC-GT program is available for residential customers who live in DACs and meet the income eligibility requirements for the California Alternate Rates for Energy (CARE) and Family Electric Rate Assistance (FERA) programs. The CS-GT program is structured similarly to the DAC-GT program but is intended to drive more local, community-developed solar projects. The CS-GT program requires community involvement with the solar project through a local sponsor and will result in a solar facility serving a nearby community. The CS-GT program is open to all residential customers located in a DAC, with at least 50% of the program's capacity reserved for CARE and FERA eligible customers.

Both programs are funded first through greenhouse gas (GHG) allowance proceeds. If such funds are exhausted, the programs will then be funded through public purpose program (PPP) funds.

Pursuant to D.18-06-027, Community Choice Aggregators (CCAs) may develop and implement their own DAC-GT and CS-GT programs in addition to the IOU's programs. Resolution E-4999 allocated a portion of the program capacity to CCAs and determined that any CCA interested in running the programs must file an Implementation Advice Letter (AL) with the CPUC by 1/1/2021.

MCE herby submits the Implementation Plan for the Disadvantaged Communities Green Tariff and Community Solar Green Tariff Programs (Implementation Plan), detailing the rules and requirements for the two programs. More specifically, the Implementation Plan contains the following sections:

- Customer eligibility and enrollment
- Rate and discount design
- Procurement
- Budget and cost recovery
- Marketing, education, and outreach
- Reporting
- Program measurement and evaluation

2. CUSTOMER ELIGIBILITY AND ENROLLMENT

This section establishes customer and sponsor eligibility and enrollment terms. These terms can also be found in the DAC-GT and CS-GT tariff schedules.

2.1. DAC-GT Program

2.1.1. Customer Eligibility

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.[1]

DACs are defined under D.18-06-027 as communities that are identified in the CalEnviroScreen 3.0 tool as among the top 25 percent of census tracts statewide, plus the census tracts in the highest five percent of CalEnviroScreen's Pollution Burden that do not have an overall CalEnviroScreen score because of unreliable socioeconomic or health data.[2] In the event that the CalEnviroScreen tool is updated, and MCE has unsubscribed program capacity available, MCE will file a Tier 1 Advice Letter within 30 days of the release of the new version to update program eligibility rules. Customers who are already enrolled in DAC-GT will retain their eligibility even if their census tract is no longer considered a top 25 percent DAC under the revised CalEnviroScreen.

Eligibility of customers is verified at the level of the Service Agreement ID (SA ID). Service accounts enrolled under the following programs and services are ineligible to participate in the DAC-GT program:

- IOU bundled service;
- Direct access customers;
- Standby service;
- Net energy metering (NEM) rates;
- Non-metered service;
- Rates that are not CARE- or FERA-eligible;
- Non-residential rates;

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[1] Customers must be eligible to participate in either the CARE or FERA programs; they are not required to be enrolled under those programs to be eligible to participate in DAC-GT. CARE/FERA eligibility is established as currently defined under those programs.

[2] D.18-06-027, *Alternate Decision Adopting Alternatives to Promote Solar Distributed Generation in Disadvantaged Communities*, at p.16 and p.53.

- Master-metered customers;[3]
- Schedule CS-GT, Community Solar Green Tariff.

2.1.2. Customer Enrollment

Enrollment of customers under Schedule DAC-GT occurs at the level of the SA ID. Subscribing customers have their electricity met with 100% solar energy based on their actual usage each month and will receive a 20% discount on their otherwise applicable tariff for the enrolled SA IDs. Customer enrollment is capped at a maximum of 2 MW solar equivalent per SA ID.[4]

The DAC-GT program allows eligible customers to purchase renewable electricity produced by a pool of community solar projects for up to 100% of their electric usage. More specifically, customers subscribe to a percentage of the total program's capacity based on their previous 12-month average monthly usage.[5] The following example describes the calculation of the customer's subscription allocation in more detail: We assume for this example that a residential customer has an average historical usage based on the previous 12-months of 500 kWh per month. The total program capacity is 4.646~~31~~MW which produce approximately 1017~~944~~ MWh of solar power per month.[6] The customer's subscription allocation is then calculated as a percentage of the average monthly output of the solar system (500 kWh/ 1,017~~944~~,000 kWh = 0.00049~~53~~% of monthly output of the pool of solar projects). In this example, the customer will subscribe to 0.00049~~53~~% of the total capacity under the DAC-GT program. This percentage allocation is set at the time of customer subscription but may be revisited periodically to ensure accurate allocations of project capacity. The program is fully subscribed once program enrollment meets 100% of total capacity under the program.

MCE will automatically enroll any eligible customers that live in one of the top 10% of DAC census tracts statewide that are located in MCE's service area until customer subscriptions reach 4.646~~31~~ MW (MCE's DAC-GT program cap). Priority will be given to customers who have made an effort to pay, as defined by at least 4 full or partial payments in the last 8 months

[3] MCE cannot ensure that all tenants under one master-meter are eligible for the CARE or FERA program, as the sub-metered tenants are not MCE direct customers. Hence, master-metered accounts are not eligible for the DAC-GT program.

[4] This limitation does not apply to a federal, state, or local government, school or school district, county office of education, the California Community Colleges, the California State University, or the University of California.

[5] If previous 12-month historical usage is not available, the average monthly usage will be derived from as many months as available. For customers establishing new service, the class average monthly usage will be used.

[6] Based on a capacity factor of 30%.

(category 1). If program capacity remains unsubscribed after enrolling these customers, MCE will enroll additional customers in the following order:

- Customers who have made at least 3 full or partial payments in the past 8 months (category 2);
- Customers who have made at least 2 full or partial payments in the past 8 months (category 3).[7]

If there is not enough program capacity to enroll all customers in a given category under the DAC-GT program, customers from the respective category will be randomly selected for program enrollment. All remaining customers will be place on a waitlist. MCE will monitor program attrition on a monthly basis and enroll additional customers from the waitlist as program capacity becomes available.

Customer enrollment will be available immediately upon program launch. A participating customer can remain on the DAC-GT tariff for up to 20 years from the time of enrollment. There is no contract required when enrolling in the DAC-GT program. Customers may remain enrolled for any number of months, and there is no enrollment or cancellation fee. Customers may choose to cancel participation in the program at any point in time. Cancellation of a customer's participation will become effective on the next meter read date; cancellations made within five (5) business days of the next meter read date may not be changed for an additional billing cycle. Customers who, after enrollment into the DAC-GT Program, become ineligible for CARE or FERA will be un-enrolled from the DAC-GT program.

The customer will be placed on the DAC-GT rate on the first day of the next billing cycle where the billing cycle start date occurs at least five (5) business days after the date of the customer's request. A customer request that is received within five (5) business days of the customer's next billing cycle may result in the customer being placed on the DAC-GT rate in the following billing cycle.

A customer's service under this schedule is portable within MCE electric service area as long as the customer continues to live in a DAC as defined under the program and continues to meet all other eligibility requirements. If the customer is found to still be eligible, MCE retains their status as a program participant and does not require the customer to go on a waitlist, as long as the customer's turn-on date at the new location is within 90 days of their final billing date at their original location.

[7] MCE is expecting to serve approximately 1,762 customers under the DAC-GT program, based on the program cap of 4.31MW (assuming a 28% capacity factor of the solar project and an average customer usage of 500 kWh per month). Based on data through August 2020, 1411 customers in the top 10% DACs have made at least 4 payments in the past 8 months, 1604 customers have made at least 3 payments in the past 8 months and 1748 customers have made at least 2 payments in the past 8 months..

2.2. CS-GT Program

2.2.1. Customer Eligibility

The CS-GT program is available to residential customers who live in DACs (as defined above)[8] and receive generation service from MCE. Non-residential customers are not eligible to participate, except for the project sponsor (see more information on sponsor eligibility rules below). A solar generation project supporting the program must be located within five miles of the participating customers' census tract.[9] 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.[10]

Eligibility of customers is verified at the level of the SA ID. Service accounts enrolled under the following programs and services are ineligible to participate in the CS-GT program:

- IOU bundled service;
- Direct access customers;
- Standby service;
- Net energy metering (NEM) rate;
- Non-metered service;
- Schedule DAC-GT, Disadvantaged Communities Green Tariff.

Master-metered customers may participate in the CS-GT program so long as they enroll all of their usage under the master-metered account in the program. Individual tenants of a master-meter customer are not eligible to participate on an individual basis. Master-metered customers must also meet all other eligibility requirements.

In the event that CalEnviroScreen is updated, MCE will file a Tier 1 AL within 30 days of the release of the new version to update program eligibility rules. As with the DAC-GT program, all customers in an eligible DAC at the time of a project's initial energy delivery date will remain eligible to subscribe to that CS-GT project, even if their DAC designation changes in subsequent

[8] Customers who live in the San Joaquin Valley (SJV) pilot program communities (as defined in R.15-03-010) are also eligible for the program even if their community is not among the top 25% DACs as defined by CalEnviroScreen. Currently, there are no CCAs in existence in the SJV pilot communities. However, if the SJV pilot communities expand, an existing CCA expands or a new CCA is created, those customers would also be eligible for the CCA CS-GT program.

[9] Per D.18-12-015, *Decision Approving San Joaquin Valley Disadvantaged Communities Pilot Projects*, CS-GT projects in SJV pilot communities can be located within a 40-mile radius of the pilot communities they serve. As discussed above, there are currently no CCAs in existence in SJV pilot communities. However, if this changes, these locational requirements would also apply to CCA CS-GT programs.

[10] As under the DAC-GT program, customers do not need to be currently enrolled under CARE/FERA to be eligible for the CS-GT program. However, they will be encouraged to enroll under the CARE or FERA program through the existing IOU enrollment process when enrolling under the CS-GT program.

iterations of CalEnviroScreen. This grandfathered eligibility will apply to both existing subscribers and customers not previously subscribed to the project in that same DAC, to ensure that the project's output can be fully subscribed by customers whose census tract is within 5-miles of the project.

2.2.2. Customer Enrollment

As with DAC-GT, enrollment of customers occurs at the level of the SA ID. Customer enrollment is capped at a maximum of 2 MW solar equivalent per SA ID.[11]

The CS-GT program allows eligible customers to purchase renewable electricity produced by a local community solar project for up to 100% of their electric usage. More specifically, customers subscribe to a percentage of the solar system's project capacity based on their previous 12-month average monthly usage.[12] As described below, participating customers will receive a 20% discount on their otherwise applicable tariff for enrolled SA IDs. Customers cannot be subscribed to more than one CS facility at any time.

The following example describes the calculation of the customer's subscription allocation in more detail: We assume for this example that a residential customer has an average historical usage based on the previous 12-months of 500 kWh per month. The customer subscribes to a 100 kW community solar project with an estimated average monthly output of 21,900 kWh.[13] The customer's subscription allocation is then calculated as a percentage of the average monthly output of the solar system (500 kWh/ 21,900 kWh = 2.3% of monthly output). In this example, the customer will subscribe to 2.3% of the project's capacity (or 2.3kW of the 100kW system). This percentage allocation is set at the time of customer subscription but may be revisited periodically to ensure accurate allocations of project capacity.

Customers interested in enrolling in the CS-GT program can sign up with MCE online, by phone, or with a hardcopy application. MCE will verify customer eligibility based on service account address to verify DAC census tract and 5-mile locational requirement. CARE/FERA enrollment status will also be identified to track subscription of low-income customers. Enrollment of new customers is available until 100% of project capacity is subscribed. Enrollment attrition will be reviewed on a monthly basis, and the program will be available for new enrollments until the

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[11] This limitation does not apply to a federal, state, or local government, school or school district, county office of education, the California Community Colleges, the California State University, or the University of California.

[12] If previous 12-month historical usage is not available, the average monthly usage will be derived from as many months as available. For customers establishing new service, the class average monthly usage will be used.

[13] Based on a capacity factor of 30%.

project is fully subscribed.

Low-income customers will be enrolled on a first-come, first-served basis. Once 50 percent of project capacity is subscribed by low-income customers, non-low-income qualified customers located in DACs will become eligible for enrollment. These customers can be recruited before the 50 percent subscription requirement for low-income customers is met. However, they will be placed on a waitlist until 50 percent of the project capacity is subscribed by low-income customers.

MCE will assess the subscription rate of low-income customers on a monthly basis after the Power Purchase Agreement (PPA) is awarded. If the low-income subscription rate drops below 50 percent over the life of the project, existing non-low-income customers are not required to go back on a waitlist. However, new enrollments of non-low-income program participants will be barred until the 50 percent low-income threshold is met again. During this time, new enrollments of non-low-income participants will be put on a waitlist. MCE will inform the Commission's Energy Division Director in writing if the low-income enrollment rate drops below 35 percent of project capacity.

The customer will be placed on the CS-GT rate on the first day of the next billing cycle where the billing cycle start date occurs at least five (5) business days after the date of the customer's request. A customer request that is received within five (5) business days of the customer's next billing cycle may result in the customer being placed on the CS-GT rate in the following billing cycle.

Customer enrollment will be available immediately upon program launch. There is no contract required when enrolling for the CS-GT program. Customers may enroll for any number of months, and there is no enrollment or cancellation fee. Cancellation of a customer's participation will become effective on the next meter read date; cancellations made within five (5) business days of the next meter read date may not be changed for an additional billing cycle. A participating customer can remain on the CS-GT tariff for the duration of the project's contract term, or up to 20 years, whichever is less. Customer participation in the program automatically terminates should the PPA between MCE and the developer for the CS-GT facility to which the customer is subscribed be terminated or the delivery term ends.

A customer's service under this schedule is portable within MCE electric service area as long as the customer continues to live in a DAC as defined under the program and continues to meet all other eligibility requirements (including the locational requirement). If the customer is found to still be eligible, MCE will retain their status as a program participant and will not require the customer to go on a waitlist, as long as the customer's turn-on date at the new location is within 90 days of their final billing date at their original location.

2.2.3. Sponsor Eligibility

Under the CS-GT program, community involvement must be demonstrated by a non-profit community-based organization (CBO) or a local government entity "sponsoring" a community solar project on behalf of residents. Local government entities include schools. The sponsor's role is to work with the project developer to encourage program participation in the community. Sponsors are also required to include job training and workforce development in their efforts to benefit the local communities which would benefit from their projects. Additional sponsor requirements are described in the Procurement section below.

To receive the 20% discount on eligible as described below, the sponsor must fulfill the following requirements:

1. The sponsor must be an MCE electric customer;
2. The sponsor must take service on the Community Solar Green Tariff;
3. The sponsor must be located in the same geographic areas as any other customer, i.e., within a disadvantaged community with the solar project being located 5 miles from the sponsor's census tract;
4. Fifty percent of the project's capacity must be subscribed by low-income customers; and
5. The sponsor must meet all other eligibility requirements of any participating customer as described in the section on CS-GT customer eligibility above.

CBOs or local government entities that do not fulfill all or any of these requirements may still become project sponsors; however, they are not eligible to receive the 20 percent discount.

There may be more than one sponsoring entity supporting a single community solar project. Multiple sponsors may share the 20 percent discount as long as all sponsors meet the eligibility requirements outlined above.

A sponsor may also be (although is not required to be) a site host.[14]

2.2.4. Sponsor Enrollment

Sponsors of a CS-GT project are subject to the same enrollment rules and requirements as described above for residential customers participating in the program. For example, enrollment occurs at the level of the SA ID and is capped at a maximum of 2MW of solar equivalent per SA ID.[15]

The sponsor's subscription allocation is also calculated the same way as for any other participating customer with one modification. A sponsor's subscription allocation is limited to a maximum of 25 percent of the project's energy output (not to exceed the sponsor's energy needs).

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[14] For the purposes of this program, the concept of a "host" only refers to a customer site where the project is located. The community solar project must be located in-front-of-the meter, even if located at a customer host site. Accordingly, all concepts and rules of an in-front-of-the-meter program continue to apply.

[15] This limitation does not apply to a federal, state, or local government, school or school district, county office of education, the California Community Colleges, the California State University, or the University of California.

To illustrate this in more detail, we use the same example as before (100kW solar project with a monthly output of 21,900 kWh). We assume now that the total monthly usage among all the sponsor's eligible SA IDs is 10,000 kWh, which is larger than 25% of monthly project output (5,475 kWh). In this example, the sponsor's subscription allocation is limited to 25% of project output per month, and the sponsor will receive the discount on only 5,475 kWh.

If two or more sponsors are designated, the sponsors will need to inform MCE in writing of how the "discountable usage" (in this example, 5,475 kWh/monthly) are to be allocated between them.

3. RATE AND DISCOUNT DESIGN

This section describes the rules and requirements for providing the 20 percent bill discount to participating customers.

3.1. Customer Bill Discount

Participants in both the DAC-GT and CS-GT programs will receive a 20% discount on the electric portion of the bill compared to their otherwise applicable rates (OAR).[16] The discount applies as long as customers are enrolled under the programs and they comply with all the eligibility and enrollment terms described in MCE's DAC-GT and CS-GT tariff sheets.

For low-income customers enrolled in the CARE or FERA programs, the OAR is the customer's existing CARE or FERA rate.[17] Accordingly, the 20% discount for these customers will be applied to low-income customer bills after the CARE/FERA discount has been applied.

For customers who are not enrolled in CARE or FERA programs, the OAR is the customer's existing rate schedule before program enrollment. Residential customer SA IDs that are already enrolled in MCE's 100% renewable energy generation service option (i.e., MCE's "Deep Green" rate) when enrolling under the programs, will be defaulted to MCE's base rate (i.e., MCE's "Light Green" rate) for the purposes of calculating the 20% discount. In other words, MCE's Light Green rate becomes the de-facto OAR for residential customers who are not on the CARE or FERA rate.

A customer's electric portion of the bill consists of two main parts: (1) generation portion, and (2) delivery portion. CCAs, as the generation service provider, only have timely access to customers' generation charges, and therefore will only calculate the 20% discount for the generation portion of the electric bill. The respective utility (in MCE's case PG&E) will be responsible for calculating the 20% discount of the delivery portion of the bill for CCA program participants.

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[16] D.18-06-027 at p.53 and p.74.

[17] Resolution E-4999, Conclusion 28 at p.55.

More specifically, MCE proposes the following monthly discount calculation and billing procedures for MCE program participants:

1. PG&E sends MCE customer usage information;
2. MCE calculates the 20% discount of the generation portion of the electric bill;
3. PG&E applies the CARE/ FERA discount and then calculates the 20% discount of the delivery portion of the electric bill;
4. MCE sends PG&E generation charges (reduced by 20% bill discount) for inclusion on the bill;
5. PG&E compiles the bill, sends it to customer, and gets paid by the customer;
6. PG&E pays MCE the generation charges (reduced by 20% bill discount) per established processes;
7. MCE recovers the revenue shortfall for providing the discount on the generation portion of the bill through the program's cost recovery mechanisms (see details below);
8. PG&E recovers the revenue shortfall for providing the discount on the delivery portion of the bill through the program's cost recovery mechanisms.

In regards to bill presentment, the 20% bill discount on the generation portion of the bill will be shown on the MCE portion of the bill; the 20% discount on the delivery portion of the bill is displayed on the PG&E portion of the bill.

3.2. Sponsor Bill Discount

CS-GT project sponsors who meet all of the eligibility requirements outlined above receive a 20% bill discount on enrolled SA IDs. The sponsor bill discount will be calculated based on the same methodology as described above for residential program participants with one modification. The sponsor bill discount is only applied to a sponsor's subscription allocation, i.e., limited to a maximum of 25% of the project's energy output (not to exceed the sponsor's energy needs under the enrolled SA IDs). The discount applies as long as sponsors are enrolled under the programs and they comply with all the sponsor eligibility and enrollment terms described above. If two or more sponsors are designated, both sponsors must inform MCE in writing of how the "discountable usage", capped at 25% of the project's energy output, are to be allocated among them. MCE will then calculate the applicable discount to each sponsor accordingly.

The sponsor's discount is available to sponsors only after the community solar project has reached its required minimum 50% low-income subscription rate. If the subscription rate of low-income customers drops under 50% of project capacity at any time throughout the life of the project, the sponsor bill credit will not be revoked.

4. PROCUREMENT

Per Resolution E-4999, MCE has been allocated 4.31 MW for its DAC-GT program and 1.11 MW for its CS-GT program based on the proportional share of residential customers in DACs that MCE serves.[18]

Resolution E-4999 also allows CCAs that serve customers in the same IOU service territory to share and/or trade program capacity.[19] Some CCAs in PG&E's service territory have elected to not pursue one or both of the DAC-GT and CS-GT programs and to forego their capacity allocations per Resolution E-4999. These non-participating CCAs have elected to transfer their allocations to the participating CCAs in PG&E's service territory. The involved CCAs, both participating and non-participating, have agreed to distribute the transferred capacity in equal parts among the participating CCAs. The tables below show the capacity to be transferred between CCAs under both the DAC-GT and CS-GT programs. ~~MCE is not trading/ sharing capacity under either program at this point in time but reserves the right to do so before 1/1/2021 through a supplemental Advice Letter filing.~~

Table 1: CCA Capacity Transfer under the DAC-GT Program

Transferring CCA	**Capacity being Transferred (MW)**	**Receiving CCAs**				
		EBCE	**CPSF**	**MCE**	**PCE**	**SJCE**
SVCE	0.5	0.100	0.100	0.100	0.100	0.100
SCP	0.5	0.100	0.100	0.100	0.100	0.100
3CE	0.68	0.136	0.136	0.136	0.136	0.136
TOTAL	**1.68**	**0.336**	**0.336**	**0.336**	**0.336**	**0.336**

Table 2: CCA Capacity Transfer under the CS-GT Program

Transferring CCA	**Capacity being Transferred (MW)**	**Receiving CCA**			
		EBCE	**CPSF**	**MCE**	**PCE**

[18] Resolution E-4999, Table 1 at p.14. Due to the continued growth and expansion of CCAs, MCE recommends that the Commission review CCA capacity allocations biennially and adjust the allocation of remaining program capacity in each IOU's distribution service territory proportional to the then current share of residential customers in DACs. The first capacity allocation adjustment should occur by January 1, 2022 and every two years thereafter.

[19] Resolution E-4999 at p.54, Findings and Conclusions ¶ 17.

SJCE	0.36	0.0900	0.0900	0.0900	0.0900
SVCE	0.09	0.0225	0.0225	0.0225	0.0225
SCP	0.06	0.0150	0.0150	0.0150	0.0150
3CE	0.18	0.0450	0.0450	0.0450	0.0450
TOTAL	**0.69**	**0.1725**	**0.1725**	**0.1725**	**0.1725**

The capacity transfer under the DAC-GT program results in an increase of 0.336 MW for each participating CCA. Added to MCE's original program capacity of 4.31 MW, this leads to a total program capacity of 4.646 MW for MCE under the DAC-GT program. The capacity transfer under the CS-GT program results in an increase of 0.1725 MW for each participating CCA. Added to MCE's original program capacity of 1.11 MW, this leads to a total program capacity of 1.2825 MW for MCE under the CS-GT program.

All renewable energy resources procured on behalf of customers participating in the DAC-GT and CS-GT programs, as well as interim resources, will comply with the California Air Resources Board's (CARB) Voluntary Renewable Electricity Program. California-eligible GHG allowances associated with these purchases will be retired on behalf of participating customers as part of CARB's Voluntary Renewable Electricity Program.

It is MCE's understanding that Green-e certification is not be feasible for the DAC-GT program under current program rules. Per D.18-06-027, 100% of a customer's annual usage is covered with solar energy under the program. Subscription to the program is based on a customer's historical usage quantities and once subscribed, no annual true-up mechanism between the sum of participating customer's total annual usage and total annual generation of all resources under the DAC-GT program will occur. It could be the case that in any given year, total customer load under the program exceeds total generation of all resources under the program. In MCE's understanding, the Green-e Energy Code of Conduct does not allow for this to happen. Hence, MCE proposes that Green-e certification is not required as a program element.

4.1. DAC-GT Program

DAC-GT projects must be located in a DAC within the same IOU service territory as the customers being served. DAC-GT projects located in census tracts that were previously considered a DAC under the program, but are no longer scored as such due to updates to the CalEnviroScreen tool, will continue to be eligible to serve customers under the DAC-GT program.[20]

MCE has a total program ~~was assigned a~~ capacity ~~allocation~~ of 4.646~~31~~ MW under~~for~~ the DAC-GT program. Eligible projects must be sized between 500 kW and 20 MW (4.646~~31~~ MW in MCE service area due to the program cap). MCE will consider both full deliverability and energy-only projects in the solicitations.

MCE will issue DAC-GT solicitations once a year until the program cap is reached. The solicitation process will follow these guiding principles:

1. The project is selected through a competitive solicitation;
2. MCE executes a Power Purchase Agreement (PPA) with a developer for a solar project;
3. There is no direct relationship between the customer and the project developer;
4. Subscribing customers receive 100% renewable energy; and
5. Subscribing customers receive a defined bill credit.

Eligibility for procurement under the DAC-GT program requires that bid pricing must be at or below the statewide CCA cost cap provided to CCAs by the CPUC's Energy Division Staff via email on September 5, 2019.[21]

MCE will serve DAC-GT customers on an interim basis until the new DAC-GT resources come online utilizing existing resources that meet all of the requirements of the DAC-GT program. MCE proposes to use the following solar resource under MCE's portfolio as interim resources for the DAC-GT program:[22]

- Cottonwood Solar Project (Goose Lake facility)
- Address: 15004 Corocan Rd., Lost Hills, CA 93249
- Nameplate capacity: 12 MW
- Commercial Online Date: 2015

[20] In the event that the CalEnviroScreen tool is updated, MCE will file a Tier 1 Advice Letter within 30 days of the release of the new version to update program eligibility rules.

[21] Energy Division staff explains in the email from September 5, 2019 that CCAs are expected to compare the unadjusted project bids to the price cap. In other words, CCAs should use the price cap to screen the submitted bid prices before making adjustments to those prices such as time of delivery adjustments. Energy Division staff also clarified in a workshop that the value of the CCA cost cap will change when all three IOUs procure new resources under the Green Tariff Shared Renewables (GTSR) program or under the Renewable Auction Mechanism (RAM) as-available-peaking category. Energy Division will notify the CCAs when this occurs.

[22] The solar resource is located in a DAC within PG&E's distribution service territory and is currently under contract with MCE.

Once the new DAC-GT solar resources come online, MCE DAC-GT customers will be transferred to these projects.

4.2. CS-GT Program

CS-GT projects must be sited in a DAC within the same IOU service territory as the customers being served and must also be located within 5 miles of the benefitting customers' DAC census tract. CS-GT projects located in census tracts that were previously considered a DAC under the program, but are no longer scored as such due to updates to the CalEnviroScreen tool, will continue to be eligible to serve customers under the CS-GT program. [23]

MCE has a total program~~was assigned a~~ capacity ~~allocation~~ of 1.2825~~11~~ MW ~~in Resolution E-4999 for~~under the CS-GT program.[24] Eligible projects have no minimum size and a maximum size of 3 MW (1.2825~~11~~ MW in MCE service area due to the program cap). MCE will consider both full deliverability and energy-only projects in the solicitations.

MCE will issue CS-GT solicitations once a year until the program cap is reached. Solicitations will be run in conjunction with the DAC-GT program's solicitations. However, the DAC-GT and CS-GT program will each have separate capacity allocations and bid requirements under the same solicitation. The solicitation process will follow the same guiding principles as for the DAC-GT program:

- The project is selected through a competitive solicitation;
- MCE executes a Power Purchase Agreement ("PPA") with a developer for a solar project;
- There is no direct relationship between the customer and the project developer;
- Subscribing customers receive up to 100% renewable energy; and
- Subscribing customers receive a defined bill credit.

Eligibility for procurement under the DAC-GT program requires that bid pricing must be at or below the statewide CCA cost cap provided to CCAs by the CPUC's Energy Division Staff via email on September 5, 2019.[25]

Twenty-five percent of each project's capacity must be subscribed by eligible low-income customers prior to permission to operate (PTO). If this requirement is not met, the project will not

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[23] In the event that the CalEnviroScreen tool is updated, MCE will file a Tier 1 Advice Letter within 30 days of the release of the new version to update program eligibility rules.

~~[24] Resolution E-4999, Table 2 at p.14~~

[25] Energy Division staff clarifies in its September 5, 2019, email that CCAs are expected to compare the unadjusted CS-GT project bids to the price cap. In other words, CCAs should use the price cap to screen the submitted bid prices before making adjustments to those prices such as time of delivery adjustments.

be able to begin delivery under the contract.[26]

Community sponsorship of the project by a CBO or local government is required to be eligible to bid for the CS-GT program. Developers will be required to obtain and provide a letter of commitment from a sponsor as part of the solicitation process. A letter of commitment from a sponsor must include:

1. Demonstration of substantial interest of community members in subscribing to the project;
2. Estimated number of subscribers, with justification to ensure project is sized to likely demand;
3. A preliminary plan to conduct outreach and recruit subscribers (which may be conducted in conjunction with the developer and/or MCE); and
4. Siting preferences, including community-suggested host sites, and verification that the site chosen for the bid is consistent with community preference.

In addition to these solicitation requirements, D.18-06-07 also established several metrics for prioritization of CS-GT project bids.[27] First, MCE will prioritize projects located in the top 5% census tracts of disadvantaged communities per CalEnviroScreen 3.0 (if applicable). Second, MCE will grant priority for projects that leverage other government funding such as a state Community Services Department (CSD) grants, or projects that provide evidence of support or endorsements from programs such as Transformative Climate Communities or other local climate initiatives. Third, MCE will also prioritize job training and workforce development factors and will require workforce development for all projects, including local hiring and targeted hiring, to enable creation of job opportunities for low-income communities.

To encourage the development of CS-GT projects, MCE will provide support to local CBOs and project developers to identify potential community solar sites within its service territory as needed. As a local government agency, MCE has existing relationships within its communities that can be leveraged to enhance the success of the CS-GT program.

5. BUDGET AND COST RECOVERY

This section describes the rules and requirements regarding program costs and budget, funding and cost recovery mechanisms, and the process of reviewing program costs.

[26] No interconnection or other project development processes will be influenced. The project can be finalized but payment on the delivery will not be started until 25% low-income customer subscription is achieved.

[27] D. 18-06-027 at p. 82ff

5.1. Budget

Program Administrators must submit annual program budget forecasts via a Tier 1 Advice Letter by February 1st of every year for the following program year. Each Advice Letter must include separate program budget forecasts for the DAC-GT and CS-GT programs and must clearly identify any costs that are shared between the programs.

Annual budget submissions will include, at a minimum, the following budget line items:

1. Generation cost delta, if any;[28]
2. 20 percent bill discount for participating customers;
3. Program administration costs;
4. Marketing, education and outreach (ME&O) costs; and
5. Program evaluation costs.

Generation Cost Delta

For subscribed energy, the generation cost delta is the net value of renewable resource costs and other generation-related costs used to support the program that are more or less than the resource and other generation-related costs for the typical residential rate.

MCE will calculate the generation cost delta by comparing the sum of energy contract prices, incremental Resource Adequacy (RA), and incremental shaping costs for DAC-GT and CS-GT resources with the rate for MCE's Light Green Basic Residential[29] service. The cost components are defined as follows:

- The **energy generation cost** for the DAC-GT program will be the weighted average of the energy contract prices of all solar projects under the program;
- The **energy generation cost** for the CS-GT program will be the weighted average of the specific solar project that the customer subscribes to;
- The incremental **RA value or cost** of DAC-GT and CS-GT resources are determined by CAISO Net Qualifying Capacity multiplied by 2020 RA value benchmarks, compared against the RA cost as determined by PG&E residential load profile multiplied by the 2020 RA value benchmarks;

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[28] Resolution E-4999 establishes that *above market* generation costs should include net renewable resource costs in excess of the otherwise applicable class average generation rate that will be used to calculate the customers' bills. In conversations with the CPUC's Energy Division after the release of the Resolution, it was clarified that this budget line item is intended to cover both a potential higher, as well as lower, cost of the DAC-GT/ CS-GT resources than the otherwise applicable class average generation rate. Hence, the term is updated to state the "*Delta of generation costs* between the DAC-GT/ CS-GT resources and the otherwise applicable class average generation rate".

[29] Equivalent to PG&E's tiered E-1 rate. This rate currently serves approximately 90% of MCE residential accounts.

- The incremental **shaping value or cost** of DAC-GT and CS-GT resources as determined by the applicable resources' production profile multiplied by 2019 (updated annually) CAISO Day-Ahead LMP for PG&E DLAP, compared against the PG&E residential load profile multiplied by the 2019 CAISO Day-Ahead LMP for PG&E DLAP.

The delta between the base rate and the total generation cost of the DAC-GT or CS-GT resource will then be multiplied by the volume served each month by each program to arrive at the total above-market generation cost or below-market generation savings from the program.

The above/below market generation costs, if any, will not be charged to participating customers and thus will not appear on the customers' bills. Instead, the cost delta, if any, will be tracked in the background and will be charged as program costs (or credits) and recovered through GHG allowance revenue and PPP funds as outlined below.

Because new DAC-GT/ CS-GT facilities will be contracted to MCE to provide all of their output, any potential above-market costs associated with unsubscribed output will also be covered by program funds.[30] MCE will seek to sell excess energy not used by program participants to the market and any revenue received will be applied as a credit towards program funds. In preparation of the annual budget advice letter, MCE will true up the full costs for unsubscribed generation under the programs against any revenue received and will charge the remainder to the programs as a separate budget line item.

Participant Bill Discount

As described above, program participants will receive a 20-percent discount on the otherwise applicable rate of eligible SA IDs. MCE's annual program budget will include the estimated total amount of revenue loss to be experienced by providing the 20% discount on the generation portion of the bill. More specifically, this calculation will be based on forecasted monthly enrollment in each program and average monthly bills by customer class.

Program Administration and ME&O Costs

Under the DAC-GT and CS-GT programs, program administrators (PAs) can recover all program administration and ME&O costs from program funds. MCE will track program costs for the DAC-GT and CS-GT programs in separate accounts.

Administrative budget must be broken out into:

1. Program management;
2. Information technology (IT);
3. Billing operations;
4. Regulatory compliance; and

[30] D.18-06-027 at p. 83.

5. Procurement.

Marketing, education and outreach (ME&O) costs must be broken out in:

1. Labor costs;
2. Outreach and material costs;
3. Local CBO/ sponsor costs (for CS-GT only).

Resolution E-4999 establishes a budget cap of 10% of the total budget for program administration costs and a budget cap of 4% of the total budget for ME&O costs.[31] However, administrative and ME&O costs may be higher than these budget allocations in the first two years of program implementation, acknowledging that program start-up costs may be higher.

Program Evaluation Costs

The DAC-GT and CS-GT programs must be reviewed by an independent evaluator every three years. The first independent evaluator review of the utilities' DAC-GT and CS-GT programs is scheduled for January 1, 2021.

As CCA programs will launch after the utilities' programs, MCE proposes that the first evaluation of the CCAs' programs not occur before January 1, 2022. MCE will work with Energy Division to determine the appropriate scope, funding level and budget allocations for CCAs to include the program evaluation in their budgets for program year (PY) 2022 and subsequent PYs.

In addition to budget forecasts, annual program budget submissions must also include details on program capacity and customer enrollment numbers for both programs:

1. Existing capacity at previous PY close;
2. Forecasted capacity for procurement in the upcoming PY;
3. Customers served at previous PY's close; and
4. Forecasted customer enrollment for the upcoming PY.

Finally, MCE will submit the following workpapers to Energy Division staff directly:

1. Workpaper for the calculation of the generation cost delta;
2. Workpaper for the calculation of the 20% bill discount to participating customers.

Supporting worksheets used in substantiating cost estimates, including direct labor, management and/or supervisor costs, and any vendor costs, along with a breakdown of staff or contractor position descriptions, loaded hourly rates, and total hours anticipated for each task, will be provided if available.

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[31] Resolution E-4999 at p.27. The Resolutions determines that Program Administrators can submit a Tier 3 Advice Letter requesting an adjustment to the budget allocations if the need arises.

Program costs will not be charged to participating customers and will thus not appear on customers' bills. Instead, the cost categories described above will be tracked and charged as program costs to the DAC-GT and CS-GT programs.

MCE submits a budget estimate for PYs 2020 and 2021 in Attachment C to the Implementation Advice Letter.

5.2. Budget Forecasting and Reconciliation Procedures

MCE will file, by February 1 of each program year, a Tier 1 Budget Advice Letter.[32] In this Annual Budget Advice Letter filing, MCE will, for each program separately:

1. Request approval of its **forecasted budget** for the upcoming program year (e.g.; by February 1, 2021 for the 2022 PY);
2. Report its **actual expenditures** during the prior program year (e.g.; by February 1, 2021 for the 2020 PY); and
3. **Reconcile** the prior year's budget forecast with actual expenditures.

5.2.1. Budget Forecast

MCE will forecast estimated program cost for the upcoming PY for all budget categories described above. For the projected revenue loss associated with providing the 20% discount to customers, MCE will estimate the total expected revenue loss for the generation portion of the electric bill. PG&E will estimate the total expected revenue loss for the delivery portion of the electric bill.

5.2.2. Report Actual Expenditures

MCE will report on actual expenditures for the previous PY for all budget categories described above. For the actual revenue loss associated with providing the 20% discount to customers, MCE will report on the actual total revenue loss for the generation portion of the electric bill. PG&E will report on the total actual revenue loss for the delivery portion of the electric bill.

The Annual Budget Advice Letter will be the mechanism for the Commission and stakeholders to review MCE actual program costs and performance. Based on the information provided in MCE's Annual Budget Advice Letter, PG&E can include a summary of actual program expenditures for the previous PY in the ERRA Compliance Review.

5.2.3. Budget Reconciliation

In the Annual Budget Advice Letter, MCE will true up forecasted program costs against actual expenditures by budget category for the prior PY. Any unspent funds from the prior PY will be used to offset the forecasted budget for the upcoming PY. If actual expenditures exceeded the

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[32] The budgets for PY 2020 and 2021 are included as an attachment to this filing, hence no additional Tier 1 Advice Letter was required by February 1, 2020 for the 2021 PY.

forecast in the previous PY, MCE will add the shortfall to the forecasted budget for the upcoming PY.

5.3. Cost Recovery Procedures

Pursuant to D.18-06-027, the DAC-GT and CS-GT programs are funded first through available GHG allowance proceeds. If such funds are exhausted, the programs will be funded through public purpose program (PPP) funds. More specifically, if total forecasted annual program costs for the programs for all PAs in an IOU's service territory (i.e., IOU and CCAs) are less than the estimated GHG allowance revenues available for the programs in that IOU's service territory, all estimated program costs will be set aside from GHG allowance revenues. If total forecasted annual program costs for all PAs in an IOU service territory are greater than the GHG allowance revenues available for the programs, all available GHG allowance revenues will be set aside for the programs, and the shortfall in funds will be allocated to PPP funds.

D.18-06-027 authorizes CCAs to access GHG allowance revenues and/or PPP funds to run the DAC-GT and CS-GT programs.[33] The IOUs administer the GHG allowance revenues and collect PPP funds, and have established balancing accounts for the DAC-GT and CS-GT programs. CCAs are not in the position to either access those funds directly or establish balancing accounts to track program costs. Therefore, MCE requests that the Commission direct PG&E to modify its DAC-GT and CS-GT balancing accounts to include a sub-account to track the funding and costs of MCE's DAC-GT and CS-GT programs. Additionally, PG&E will be responsible for determining and tracking whether and how much of the funding for MCE's DAC-GT and CS-GT programs comes from GHG-allowance revenues versus PPP funds.

Once the Commission approves MCE's Annual Budget Advice Letter, PG&E will include the total budget estimate for the upcoming PY for MCE's DAC-GT and CS-GT programs in the ERRA Forecast filing due in early June of each year. Once PG&E receives approval of its ERRA Forecast from the Commission, PG&E will set aside the requested MCE budget in a sub-account of its DAC-GT and CS-GT balancing accounts. PG&E will then transfer program funds to MCE in four quarterly installments (by January 1, April 1, July 1 and October 1 of each year) for the upcoming quarter.[34]

If the ERRA Forecast is not approved by January 1 of a given PY, PG&E will transfer all past due funds to MCE within thirty days of issuance of such approval.

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[33] D.18-06-027, Ordering Paragraph 17, at p. 104.

[34] In 2020, depending on the timing of the Commission's approval of this Advice Letter, PG&E will include both the PY 2020 and PY 2021 budget estimates in its 2021 ERRA Forecast filing in early June or in its 2021 ERRA November update. Once the 2021 ERRA Forecast is approved, PG&E will transfer all past due PY 2020 funds within thirty days of issuance of such approval.

6. MARKETING, EDUCATION AND OUTREACH

MCE will establish a ME&O program to promote customer participation in the DAC-GT and CS-GT programs. MCE plans to directly implement the ME&O program and execute outreach.

MCE is submitting a ME&O plan for PYs 2020-2021 in Attachment D to the Implementation Advice Letter.[35] The ME&O plan discusses specific methods for customer outreach, including any coordination with local CBO sponsors and associated funding to market the CS-GT program. The plan addresses how MCE will work to identify residential customers in DACs who are likely eligible for the CARE and FERA programs, but who are not yet enrolled. Finally, the plan discusses how to leverage existing customer programs to market the CS-GT programs.

As customers will be auto-enrolled to the DAC-GT program, ME&O efforts for this program will focus on customer education and awareness. MCE will provide customers with information about the program itself but will also use the opportunity to increase customer awareness about other energy savings opportunities, participation in other clean energy programs and rate options.

MCE will file annual ME&O plans and detailed budgets by February 1 of each year for the upcoming PY, starting in 2021.

7. REPORTING

Within 30 calendar days after the end of each calendar quarter, MCE will file a quarterly report for both programs, distinguishing between the DAC-GT and CS-GT program data. The quarterly report will detail:

- Procured capacity;
- Online capacity;
- DACs in which projects are located;
- Number of participating customers in each DAC within MCE's service territory;
- Number of customers who have successfully enrolled in CARE and FERA in the process of signing up for the DAC-GT or CS-GT programs.

The quarterly report will be filed in R.14-07-002 and served onto the same service list.

Semi-annually, within 30 calendar days after the end of each six-month period of the year, MCE will report the following information for CS-GT projects to the Commission's Energy Division Central Files:

[35] The ME&O plan and budget for PY 2020 are subject to change depending on the date of approval of the Implementation Advice Letter.

- Number of income-qualified customers subscribed to each project and the capacity those customers are receiving;
- Whether a waitlist of non-income-qualified customers exist and the size of that list;
- If project sponsors are receiving bill credits under CS-GT projects and the size of each sponsor's subscription; and
- The number of master-metered properties served on the CS-GT tariff and the total capacity those properties are subscribed to receive.

MCE's first quarterly or semi-annual report will be filed on the first scheduled due date after customer enrollment begins.

8. PROGRAM MEASUREMENT AND EVALUATION

An independent evaluator will review the utilities' DAC-GT and the CS-GT programs every three years beginning in 2021.[36] The CS-GT program must also be assessed by the same independent evaluator one year after program launch.[37]

MCE proposes commencing independent evaluation for CCA DAC-GT and CS-GT programs at the beginning of the upcoming PY after customers have been enrolled under the program for a minimum of one full year (e.g. if the DAC-GT program were to launch with interim resources by the fall of 2020, the first program evaluation would occur on January 1, 2022). MCE will work with Energy Division to determine the appropriate scope, funding level and budget allocations for CCAs to include the program evaluation in their program budgets for PY 2022 and subsequent PYs.

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[36] The CPUC's Energy Division will select the independent evaluator through a Request for Proposal (RFP) process managed by San Diego Gas & Electric Company on behalf of the Commission. The RFP process will be led by staff from the Commission's Energy Division, and Energy Division staff will make the final decision on the winning bidder.

[37] Resolution E-4999 clarified that it is appropriate to interpret the first year of the CS-GT program as the first-year customers are able to subscribe to projects. Thus, if no customers have subscribed to CS-GT projects by 2021, the initial independent evaluator review in 2021 will replace the evaluation of the CS-GT program after the first year.

APPENDIX B

December 2, 2020

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

RE: CCA Capacity Transfer under the Disadvantaged Community Green Tariff and Community Solar Green Tariff Programs

Resolution E-4999 allows Community Choice Aggregators ("CCAs") that serve customers in the same investor-owned utility ("IOU") service territory to share and/or trade program capacity.[1] The resolution also stipulates that if a CCA elects to trade or share capacity, the trade must be affirmed in writing by all CCAs whose program capacity is implicated in the proposal. This letter affirms the trading of capacity between CCAs under the Disadvantaged Community Green Tariff ("DAC-GT") and the Community Solar Green Tariff ("CS-GT") programs as authorized under Resolution E-4999. As confirmed in an email with Energy Division staff on November 25, 2020, this letter is being submitted as an alternative to, and in lieu of, the CCAs implicated by this proposal submitting separate written comments in response to the CCAs' advice letters.

Some CCAs in PG&E's service territory have elected to not pursue one or both of the DAC-GT and CS-GT programs and to forego their capacity allocations per Resolution E-4999. These non-participating CCAs have elected to transfer their allocations to the participating CCAs in PG&E's service territory. The CCA's involved, both participating and non-participating, have agreed to distribute the transferred capacity in equal parts among the participating CCAs and are confirming such transfer in this letter.

Capacity Transfer under the DAC-GT Program

Sonoma Clean Power ("SCP"), Central Coast Community Energy ("3CE"), formerly known as Monterey Bay Community Power, and Silicon Valley Clean Energy Authority ("SVCE") have determined to not implement the DAC-GT program and to trade their program capacity to the participating CCAs in equal parts.[2] The CCAs that will implement the DAC-GT program include East Bay Community Energy ("EBCE"), CleanPowerSF, Marin Clean Energy ("MCE"), Peninsula Clean Energy Authority ("PCE") and City of San José, in its capacity as administrator of San Jose Clean Energy ("SJCE"). The following table shows the assigned program capacity for

[1] Resolution E-4999 at 16 and 54 (Findings and Conclusions 17).

[2] Valley Clean Energy Authority has also chosen to not implement the DAC-GT program but was not included in the capacity transfer process due to its negligible program capacity allocation.

each of the non-participating CCAs per table 1 in Resolution E-4999,[3] as well as the capacity being transferred to each participating CCA.

Transferring CCA	Capacity being Transferred (MW)	Receiving CCAs				
		EBCE	CleanPowerSF	MCE	PCE	SJCE
SVCE	0.5	0.100	0.100	0.100	0.100	0.100
SCP	0.5	0.100	0.100	0.100	0.100	0.100
3CE	0.68	0.136	0.136	0.136	0.136	0.136
TOTAL	**1.68**	**0.336**	**0.336**	**0.336**	**0.336**	**0.336**

Capacity Transfer under the CS-GT Program
SCP, 3CE, SVCE, and SJCE have determined to not implement the CS-GT program and to trade their program capacity to the participating CCAs in equal parts. The CCAs that will implement the CS-GT program include EBCE, CleanPowerSF, MCE, and PCE. The following table shows the assigned program capacity for each of the non-participating CCAs per table 1 in Resolution E-4999,[4] as well as the capacity being transferred to each participating CCA.

Transferring CCA	Capacity being Transferred (MW)	Receiving CCA			
		EBCE	CleanPowerSF	MCE	PCE
SJCE	0.36	0.0900	0.0900	0.0900	0.0900
SVCE	0.09	0.0225	0.0225	0.0225	0.0225
SCP	0.06	0.0150	0.0150	0.0150	0.0150
3CE	0.18	0.0450	0.0450	0.0450	0.0450
TOTAL	**0.69**	**0.1725**	**0.1725**	**0.1725**	**0.1725**

All of the undersigned CCAs affirm the capacity transfers under the DAC-GT and CS-GT programs as described above.

Sincerely,

[3] Resolution E-4999 at 14
[4] Id.

/s/ Shalini Swaroop (Dec 15, 2020 15:24 PST)
Shalini Swaroop
General Counsel & Director of Policy
Marin Clean Energy

/s/ Michael A. Hyams (Dec 15, 2020 15:36 PST)
Michael Hyams
Deputy Manager, CleanPowerSF
San Francisco Public Utilities Commission

/s/ JP Ross (Dec 15, 2020 22:04 PST)
JP Ross
Senior Director, Local Development,
Electrification and Innovation
East Bay Community Energy

/s/
Leland Wilcox
Chief of Staff, Office of the City Manager
City of San José - San José Clean Energy

/s/ Neal Reardon (Dec 16, 2020 07:50 PST)
Neal Reardon
Director, Regulatory Affairs
Sonoma Clean Power Authority

/s/ Poonum Agrawal (Dec 16, 2020 08:31 PST)
Poonum Agrawal
Senior Regulatory Analyst
Silicon Valley Clean Energy Authority

/s/ Joseph Wiedman (Dec 16, 2020 11:23 PST)
Joseph Wiedman
Director of Legislative and Regulatory Affairs
Peninsula Clean Energy Authority

/s/ Stephen Keehn (Dec 16, 2020 12:13 PST)
Stephen Keehn
Int. Director, Regulatory Affairs
Central Coast Community Energy

cc: Service List: R.14-07-002

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Approval of Energy Savings Assistance and California Alternate Rates for Energy Programs and Budgets for 2021-2026 Program Years. (U39M)	Application 19-11-003
And Related Matters.	Application 19-11-004 Application 19-11-005 Application 19-11-006 Application 19-11-007

REPLY BRIEF OF MARIN CLEAN ENERGY

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December 18, 2020

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Approval of Energy Savings Assistance and California Alternate Rates for Energy Programs and Budgets for 2021-2026 Program Years. (U39M)	Application 19-11-003
And Related Matters.	Application 19-11-004 Application 19-11-005 Application 19-11-006 Application 19-11-007

REPLY BRIEF OF MARIN CLEAN ENERGY

Pursuant to Rule 13.11 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission" or "CPUC"), the *Assigned Commissioner's Scoping Memo and Ruling* issued February 18, 2020, and the modified schedule set forth in the May 11, 2020 *E-mail Ruling Modifying Proceeding Schedule*, Marin Clean Energy ("MCE") hereby submits this Reply Brief in support of its *Application of Marin Clean Energy for Approval of its Multifamily Whole Building Program under the Energy Savings Assistance Program 2021-2026* ("Application").

1. Introduction

As noted in MCE's Opening Brief, the LIFT 2.0 application is filed at a critical inflection point in the history of the Energy Savings Assistance Program ("ESA"). This evolution includes expanding ESA's reach to include multi-family whole building ("MFWB") programs and employing a third party implemented model in order to achieve deeper energy savings and greater impact for participating customers and properties. As does any evolution, this moment may require a break from traditional ESA practices in order to create new ones that better align with the new vision and structure for the MFWB program.[1] The questions CalAdvocates raises regarding supporting documentation for the LIFT Pilot, and the responses MCE provides, are indicative of the kind of evolution the Commission must be prepared to make in moving any part of ESA to a third-party model.

MCE maintains that its budget request is reasonable under the circumstances and should be approved. CalAdvocates' alternative proposal, as discussed below, should be rejected because it is unjustified and creates unnecessary negative consequences for LIFT 2.0 program launching activities. It also seems to rely on a mistaken interpretation of MCE's description of the impact of the proposal on program launching activities, which MCE clarifies here.

Further, MCE notes that it has already provided ESA-specific savings goals, broken out from its combined, leveraged savings goals, as has been requested by CalAdvocates. As such, MCE argues here that this issue has been resolved. Finally, MCE urges the Commission to afford MCE the flexibility to comply with any requirements it may adopt for in-language program materials in the manner that best meets the needs of the communities it serves.

2. MCE's Original LIFT 2.0 Budget Request is Reasonable Under the Circumstances and Should Be Approved

In its Opening Testimony, CalAdvocates proposed that MCE only be granted an initial budget of $1.3 million, because that is the amount MCE spent in the LIFT pilot between October 2017 and May 2020. Under the CalAdvocates proposal, MCE would submit a Tier 3 Advice Letter several months after the final decision in this proceeding containing a final measure list, analysis of the LIFT Pilot, and other information, and request the remainder of its budget therein.

[1] The Guidance Document specifically noted that the new MFWB program is not limited to the requirements set forth in prior ESA decisions. *See* D.19-06-022, Attachment A, p. 21.

CalAdvocates proposal should be rejected because it is insufficiently justified. Additionally, CalAdvocates seems to misinterpret MCE's arguments about program launching impacts, which MCE clarifies here. Finally, MCE submits that its alternative proposal, as set forth in rebuttal testimony, will lead to the same result as the CalAdvocates proposal, but with fewer negative impacts to LIFT and its ability to serve customers. For the following reasons, MCE's budget request is reasonable under the circumstances and should be approved.

a. CalAdvocates Offers Insufficient Justification for its Proposed Initial Budget Authorization for LIFT 2.0

CalAdvocates does not offer a rationale for its proposed initial budget authorization of $1.3 million, other than that is the amount MCE spent on the LIFT Pilot from its launch in October 2017 to May 2020.[2] CalAdvocates does not explain what relationship, if any, this time frame bears to the 2021-26 program cycle. Similarly, CalAdvocates does not explain the relationship, if any, between MCE's budget request for LIFT 2.0, a six-year program, and the amount spent in the LIFT Pilot during its first two and a half years. Finally, CalAdvocates does not explain why having spent 40% of the LIFT Pilot budget during its first two and a half years means that LIFT 2.0 should only receive 10% of its budget request as an initial authorization. Absent a rationale to justify PAO's proposal as relevant to the application in question, the proposal should be rejected.

b. CalAdvocates Seems to Misinterpret MCE's Argument Regarding the Impact of its Proposal on LIFT 2.0 Program Launching Activities

CalAdvocates argues that $1.3 million is adequate to launch LIFT 2.0 because this amount was adequate to launch the LIFT Pilot.[3] CalAdvocates seems to misinterpret MCE's argument regarding the impact of CalAdvocates' proposal on LIFT 2.0 program launching activities. It

[2] CalAdvocates Opening Brief at p. 17.
[3] *Id.* at 20.

appears that CalAdvocates may be referring to the cost (in staff time, etc.) to execute various program launching activities such as contracting with an implementation partner, finalizing the measures list, and building a project pipeline for LIFT 2.0. This interpretation is incorrect.

The difficulties MCE would encounter in launching LIFT 2.0 under the constraints proposed by CalAdvocates arise from uncertainty regarding the final program budget. Under CalAdvocates' proposal, MCE would not know the final approved budget for LIFT 2.0 until several months after the final decision in this proceeding. MCE cannot conduct an efficient solicitation for a third-party implementer without being able to specify the budget of the program to be implemented in the Request for Proposal. The available incentive budget, when paired with MCE's building and unit treatment goals, is essential to inform the LIFT 2.0 measure list. The available budget is similarly necessary to confirm a project pipeline without running the risk of overpromising by adding properties to the pipeline that LIFT may not actually be able to serve.

Meanwhile, while MCE attempts to conduct these activities despite the uncertainty over its final program budget, administrative costs will continue to accrue while actual program work may be delayed by the uncertainty created by the CalAdvocates proposal. This will negatively impact LIFT 2.0's cost effectiveness, the very feature CalAdvocates is trying to promote with its proposal. As discussed below, there are less disruptive ways to achieve the result CalAdvocates seeks.

c. <u>MCE's Alternative Proposal Will Lead to the Same Result with Fewer Negative Impacts</u>

As an alternative to the proposal offered by CalAdvocates, MCE asserts that it would be more reasonable for MCE to submit its final measure list and ESACET calculations, once the necessary tools are available, to the Commission via a Tier 1 Advice Letter after the third-party implementer is selected and the measure list is developed. This will serve to support MCE's budget request without creating the negative implementation impacts discussed above. As is standard practice for third-party implemented programs, MCE proposes to determine the final measure mix for LIFT 2.0 in collaboration with the selected implementer, and will conduct a public workshop to solicit feedback on the proposed measure mix prior to finalizing.[4]

The process MCE has set forth for selecting a third-party implementer and developing the LIFT 2.0 measure list will result in a portfolio that meets any requirements the Commission adopts in its final decision. Simply put, that is what it is designed to do. This process is standard practice for third-party implemented programs,[5] a model which CalAdvocates argues should apply to all of ESA.[6] It will allow the measure selection process to benefit from the selected implementer's expertise and from the expertise of the broader ESA stakeholder community as well. It also allows the final measure selection to better account for the current landscape of incentives from other programs that LIFT will leverage, including general market energy efficiency and heat pump incentives.

MCE's proposal to submit the final LIFT 2.0 measure list and accompanying ESACET calculations through an Advice Letter will better align with the measure selection process than the CalAdvocates proposal, and will result in fewer undue procedural hurdles to launching LIFT 2.0. As such, it is more reasonable than the CalAdvocates proposal, and should be approved. Low-income communities in MCE's service area and statewide are facing extraordinary hardship due to the COVID pandemic and accompanying economic downturn, and the services LIFT 2.0 will provide will create jobs as well as healthier, more livable homes in communities whose need for these benefits will be particularly acute in the coming years. MCE urges the Commission not to create undue barriers to rolling out LIFT 2.0, where a less burdensome option is available.

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[4] Rebuttal Testimony of Marin Clean Energy, p. 17 line 15 through p. 18 line 2.
[5] Testimony of Marin Clean Energy, p. 45 lines 4-6.
[6] CalAdvocates-4 (Lyser direct testimony), CalAdvocates Opening Brief, pp. 9-10.

3. MCE Has Already Presented ESA-Specific Savings Goals

CalAdvocates erroneously asserts that MCE did not provide "[c]orrect calculations for the proposed energy savings goals for LIFT 2.0, which are now based on incorrect calculations . . ."[7] However, MCE's rebuttal testimony acknowledged that the way that it *presented* its savings goals led to confusion, despite being accurately *calculated*.[8] MCE corrected this in its rebuttal testimony by providing savings goals broken out by funding stream.[9] These goals are based on, and align with, the results achieved in the LIFT Pilot. As such, MCE asserts that this issue has been resolved.

4. MCE Should Retain the Ability to Meet the Language-Access Needs of Its Customers

CalAdvocates asserts that providing educational materials in Spanish and the state's other top three non-English languages will improve program effectiveness.[10] MCE agrees with this assertion in concept and does not object to providing in-language materials in the top four most commonly-spoken non-English languages *in its service area*.[11] However, requiring MCE to conform to a statewide requirement that could lead MCE to create materials for languages that are less commonly spoken in its service area is counterproductive and cost-ineffective.

Should the Commission adopt CalAdvocates recommendation in its final decision, MCE respectfully requests the ability to submit a Tier 1 Advice Letter requesting the authority to deviate from the statewide top languages list in favor of a "top five" list that is specific to MCE's service area. This Advice Letter would contain data demonstrating which four non-English languages are most commonly spoken by its customers, and would describe how this differs from the statewide

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[7] CalAdvocates Opening Brief, pp. 16-17.
[8] Rebuttal Testimony of Marin Clean Energy, p. 9 line 20 through p. 10 line 3.
[9] *Id.* at 10, Figure 1.
[10] CalAdvocates Opening Brief, p. 27.
[11] Rebuttal Testimony of Marin Clean Energy, p. 21 lines 1-9.

"top five" list. If MCE elects not to submit an Advice Letter, it would remain bound by the Commission's statewide requirement. This alternative pathway would allow MCE to best meet the needs of its eligible customers while remaining in compliance with Commission requirements.

5. Conclusion

MCE appreciates the opportunity to respond to the above points, and respectfully reiterates its requests that the Commission:

- Approve MCE's application to offer LIFT 2.0 for the 2021-2026 ESA program cycle, including its savings goals, treatment goals, and full budget request;
- Approve MCE's request to serve as program administrator for ESA multifamily whole building program;
- Approve MCE's request to administer LIFT 2.0 as a local program;
- Approve MCE's proposal to allow LIFT 2.0 to serve a limited number of non-deed restricted, income-qualified properties, with strong renter protections;

- Authorize LIFT 2.0 to use 60% of Area Median Income as its income eligibility threshold; and
- Make the ESA Cost Effectiveness Test calculator available to MCE.

Dated: December 18, 2020

Respectfully submitted,

/s/ Stephanie Chen

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

Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Reliable Electric Service in California in the Event of an Extreme Weather Event in 2021.	R.20-11-003

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S RESPONSE TO EMAIL RULING DIRECTING PARTIES TO SERVE AND FILE RESPONSES TO PROPOSALS AND QUESTIONS REGARDING EMERGENCY CAPACITY PROCUREMENT BY THE SUMMER OF 2021

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December 18, 2020

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SUMMARY OF RECOMMENDATIONS

- The Commission should immediately schedule workshops in January to assess Summer 2021 reliability needs prior to issuing any procurement order, incorporating existing analyses identified by the California Independent System Operator Corporation (CAISO) and Southern California Edison Company (SCE) and any other available stakeholder analyses made available in advance of the workshop.

- If the Commission determines a procurement order is necessary, rather than reliance on CAISO backstop procurement, the use of centralized procurement through the investor-owned utilities' Cost Allocation Mechanisms (CAM) is a reasonable approach if narrowly scoped and constrained.

- Any increase in the existing planning reserve margin, if necessary, should not be pushed down to individual load-serving entity (LSE) resource adequacy (RA) requirements but should be met incrementally through the CAM; flowing the increase through to LSEs will bring confusion and uncertainty to the market and risk unproductive increases in LSE penalties.

- Resources procured centrally for Summer 2021 should be very narrowly targeted to out-of-market resources that would not otherwise be procured by LSEs for RA showings and should be structured to minimize disruption to LSE procurement for RA compliance.

- Procurement should be focused on Summer 2021 and exclude consideration of future procurement periods to ensure timely completion of the process.

- CAM procurement should strongly prefer one-year transactions and exclude transactions exceeding three years; preferred and demand-side management resources should be preferred where possible.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Reliable Electric Service in California in the Event of an Extreme Weather Event in 2021.	R.20-11-003

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S RESPONSE TO EMAIL RULING DIRECTING PARTIES TO SERVE AND FILE RESPONSES TO PROPOSALS AND QUESTIONS REGARDING EMERGENCY CAPACITY PROCUREMENT BY THE SUMMER OF 2021

The California Community Choice Association (CalCCA)[1] submits these comments in response to the *Email Ruling Directing Parties to Serve and File Responses to Proposals and Questions Regarding Emergency Capacity Procurement by the Summer of 2021* (Ruling), issued on December 11, 2020.

I. INTRODUCTION

Despite stakeholders' recommendations for other approaches to ensuring Summer 2021 reliability, the Commission appears inclined to default to investor-owned utility (IOU) central procurement. CalCCA continues to maintain that a more efficient, coordinated and cost-effective approach would allow the CAISO to procure resources needed in excess of known, available resources through a modified Capacity Procurement Mechanism (CPM) or, for necessary resources seeking retirement, the Reliability Must Run (RMR) program. This

[1] California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, CleanPowerSF, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, 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, Silicon Valley Clean Energy, Solana Energy Alliance, Sonoma Clean Power, Valley Clean Energy, and Western Community Energy.

approach minimizes the complexity of coordinating procurement among three IOUs, ensures that the procurement meets the needs of the system operator, and ensures that the cost of incremental capacity is broadly socialized within the CAISO control area. Such an approach would minimize interference with the existing RA market as well. CalCCA encourages the Commission to continue to consider a more central role for the CAISO in these near-term emergency conditions. Acknowledging the Commission's apparent chosen course of action, however, CalCCA's comments respond to the Ruling in the context of mandated IOU central procurement to meet anticipated Summer 2021 incremental requirements.

CalCCA responds below directly to the proposals and questions identified in the Ruling. These comments, however, also briefly address central issues skirted by the Ruling. The Ruling does not directly seek comment on the methodology that should be used to calculate the incremental RA requirement. CalCCA continues to support workshops in early January to estimate the requirement, beginning with analyses performed by the CAISO and SCE and augmented by any additional stack or other analyses presented by other stakeholders. The Ruling also avoids focus on whether the requirements should be separate from individual LSE RA requirements, as the Commission appropriately elected in Decision (D.) 19-11-016, or pushed down into those individual requirements. CalCCA strongly supports the former, noting that imposing the incremental need directly on LSEs will only increase penalties with no incremental benefit to reliability. Each of these issues is discussed below.

II. PROCUREMENT TYPE INITIAL PROPOSAL

Response to Proposal

CalCCA generally supports the Ruling's timeframe for procurement subject to refinement. Requiring a commercial operation date by June 1, 2021 ensures that incremental resources will be available during August and September. Resources that have a high likelihood of making an August 1, 2021 online date, however, should also be included in scope as "next-best" alternatives to maximize the potential for resource adequacy in the event insufficient resources are available by June 1, recognizing that resource deficiency risk increases from June through September.[2]

CalCCA also agrees with the broad categories of resources that should be included within the scope of procurement. Careful refinement of these categories, however, is critical to ensure that the resources procured to meet incremental requirements are actually incremental. In other words, the scope of procurement must be limited to resources that would not otherwise be procured by LSEs to meet their 2021 monthly system resource adequacy requirements. Without these limitations, increased demand under already tight market conditions will lead to even higher prices for LSEs trying to fill their existing capacity requirements, or shift resources that would otherwise be procured by LSEs to the IOUs with no commensurate increase in overall RA capacity. Such outcomes would be counterproductive. Thus, criteria must be set for each category to provide clear guidance to the IOUs in their procurement.

Incremental efficiency upgrades to existing power plants and incremental storage should be straightforward. Any such projects that can be achieved by Summer but have not yet been contracted should be included in the procurement scope. The availability of these projects could be identified in brief comments by developers to the Commission in early January and through the Request for Offer processes initiated by the IOUs. Re-contracting for generation that is at-risk of retirement requires guidelines. To provide these guidelines, Commission Staff, in coordination with the CAISO, should develop a public list of known resources indicating their eligibility status based on the following criteria:

2 See Comments of the California Independent System Operator Corporation on Order Instituting Rulemaking Emergency Reliability, Nov. 30, 2020 at 13-17.

- Any resource on CAISO's Final Net Qualifying Capacity (NQC) Report for Compliance Year 2021[3] should be considered an "in market" resource, and should be ineligible, unless the resource:
    - Offers more capacity than its rated NQC;
    - Offers more capacity than has been shown by LSEs or otherwise made available to CAISO in the same month for any of the prior three years; and
    - Can be clearly demonstrated to be "out of market" for LSE procurement due to other economic, legal, or regulatory reasons which require central procurement.
- Any resource indicated by LSEs for compliance with D.19-11-016 should be ineligible.
- Any resource on the CAISO's most recent Announced Retirement and Mothball list[4] should be considered an "out-of-market" resource and should be eligible.
- Any resource not indicated on CAISO's Final NQC Report for Compliance Year 2021, including firm import energy contracts, should be eligible.

The Ruling also identifies Utility Owned Generation (UOG) as a potential source of incremental procurement. Incremental procurement cannot include any existing UOG resources, since these resources should be either allocated through the CAM, assigned to bundled customers under the Power Charge Indifference Adjustment (PCIA) mechanism or otherwise offered to the market. Only expansions of existing UOG should be considered, and any such expansions – particularly those that lead to long-term commitments for ratepayers -- should be secondary to other available resources.

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3 http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx

4 http://www.caiso.com/Documents/AnnouncedResourceRetirement-MothballListPosted11062020.html#search=mothball

Finally, the Ruling suggests that resources may include RA only contracts or contracts that include tolling agreements. CalCCA assumes the intent is to describe the types of products that can be procured from the categories of resources discussed above. If there is another intent, the Commission should clarify.

Responses to Questions

1. In considering incremental authorization for procurement, what parameters should the Commission place on contracts regarding pricing, contract term, and operational characteristics?

Prices paid by the IOUs should be limited to the CPM soft offer cap plus the summer penalty price, except in the possible case of expansions, new storage projects, or resources with other compelling one-time fixed costs required to re-enter the market or expand output such as modified interconnection. If pricing exceeds the CPM soft offer cap plus the summer penalty price], however, the Commission should require support for the price on a cost basis. Finally, the Commission should require the IOUs to rely on the CAISO backstop process where there is a reasonable suspicion that market power is being exercised. The Commission should articulate a preference for one-year transactions, or three years or less should one-year transactions prove infeasible. Only if the IOUs are unable to procure the needed capacity within these terms should the Commission authorize longer term procurement. The Commission should also implement a preference for demand-side and preferred resources where feasible.

Operational characteristics of qualifying resources should be defined by the CAISO. If a resource type qualifies for procurement, its reliability value should be determined consistent with existing RA rules.

2. Should the Commission limit the total volume of incremental procurement authorized?

If the Commission declines to further develop the system needs analysis through workshops, the Commission should authorize incremental procurement reflecting the Commission-jurisdictional LSEs' share of the CAISO's estimate of additional resources necessary to secure reliability for Summer 2021. The need should be expressed in megawatts (MW), as the Commission did in D.19-11-016, rather than through a temporarily increased Planning Reserve Margin (PRM). If, however, the increase must be expressed in a temporary increase in PRM, the increase should not be arbitrary but should be tied directly to the MW of need identified in a workshop set for early January. As CalCCA noted in its reply comments, the workshop should review and harmonize recent analyses performed by the CAISO, SCE, Commission Staff, and any other stakeholders. The final procurement order should be based on rigorous analyses that incorporate both temporal and spatial dynamics, which are critical to an accurate assessment of reliability. The final MW of need should account for (a) incremental procurement above the D.19-11-016 procurement track requirement, and (b) the increased MW of reliability that can reasonably be expected to result from Emergency Load Response Programs (ELRPs) or other out-of-market programs implemented by June 2021.

If the Commission feels compelled to act without delay, it could authorize an initial tranche of procurement representing a subset of the expected procurement need while continuing to assess the full procurement need through workshops in January. This process would initiate immediate action while reducing the likelihood that a procurement order significantly over- or underestimates the full procurement need, while facilitating market discovery regarding potential available supply.

The authorized procurement should be implemented as a specific IOU requirement without pushing the requirement down into individual LSE requirements for 2021. The Commission can achieve the same reliability benefits taking this approach without taking the time to modify and debate how the additional procurement is translated to individual LSE requirements. Setting appropriate PRM levels for the RA program and translating the dual peak and post-peak requirements to individual LSEs will take additional time the Commission cannot afford if it intends to timely implement its changes. Pushing the increased requirements down to individual LSE requirements at the same time as pursuing CAM procurement will only lead to confusion and potentially greater levels of penalties. Under such a system, individual LSEs will not have sufficient information to anticipate their allocated CAM share of system RA in a manner that permits accurate portfolio balancing. In turn, this would create perverse incentives for short LSEs: where the procurement order is comingled with their RA requirement, LSEs may seek to remain short while awaiting an allocation of an unknown but sizeable quantity of centrally procured resources.

3. Should procurement that cannot achieve a commercial operation date by June 1, 2021 also be considered in this procurement authorization?

Procurement that cannot under any circumstances achieve commercial operation by August 1, 2021, should be placed in a separate procurement track of R.20-05-003. There is significant storage and generation capacity coming online through the IRP process for the peak in 2022 and beyond. Thus, any generation that cannot be used for this Summer's peak period will be redundant in light of the procurement already underway under the regular IRP process under D.19-11-016. This will limit the use of the CAM to emergency purposes and facilitate LSE self-procurement for resources that can be brought online in later periods.

4. Are there any additional considerations regarding the procurement type that the Commission should consider in issuing a procurement authorization?

Scoping the type of procurement pursued by the IOUs for purposes of Summer 2021 presents a challenge in setting the boundaries for incrementality. If the procurement scope is overbroad, the Commission risks allowing the IOUs to "skim the cream" off the RA market that LSEs will depend upon to fill their remaining monthly system RA requirements. This could lead to even higher prices for LSEs who are trying to fill their short positions or greater penalty levels for LSEs with no net gain in resource availability Summer 2021. If the scope is too narrow, the Commission risks leaving potential reliability resources on the table, defaulting to CAISO backstop procurement. The sweet spot is a scope of procurement targeting resources that would not otherwise be procured by LSEs to meet their RA requirements at the current 15 percent PRM.

The scope of IOU procurement will include the types of resources discussed above. These will be resources that require additional capital for expansion, face regulatory challenges (e.g., interconnection), have publicly signaled a risk for retirement through the CAISO's mothball list, or take advantage of a capability to develop and construct a new uncontracted resource before August 1, 2021.

In addition, procurement ordered under this proceeding should not be inconsistent with statewide planning efforts or conflict with state climate goals. While this may not be feasible if sufficient renewable generation, storage, and demand side resources are not available on the short time frame, the Commission should incorporate preferences consistent with state climate goals to the extent possible.

5. Are there additional specific issues the Commission should consider in authorizing procurement to ensure that the procurement is cost-effective under the existing circumstances, would addresses system needs, and be in the public interest?

The Commission, in coordination with the CAISO and other stakeholders, should clearly define a methodology for determining the amount of incremental need that must be met. CalCCA proposed in its reply comments workshops in early January to assess the need, starting with the analyses undertaken by the CAISO and SCE, augmented by stack or other analyses conducted by other stakeholders.

The methodology must start with an accurate assessment of the existing fleet. It thus should include all resources responding to D.19-11-016 that are set to come on-line by August 1, 2021. This should include resources that may be incremental to any individual LSE's 2021 requirement under D.19-11-016, unless the Commission determines such excess procurement would qualify for the proposed order. The methodology must fully recognize the value of uncontracted demand response (DR) resources and contributions from behind-the-meter (BTM) resources and all other "out of market" secondary demand side resources available to reduce load. The methodology should account for the estimated availability of ELRPs and other demand response resources. The determination of incremental need must account for "all of the above" and should not overlook any source of potential reliability support for Summer 2021.

The methodology should also limit the IOU procurement to the CPUC-jurisdictional share of the need. The CAISO should be responsible for requiring incremental procurement for all non-jurisdictional LSEs.

III. PROCUREMENT PROCESS INITIAL PROPOSAL

Response to Proposal

The Ruling correctly observes that the two most expeditious contracting vehicles will be bilateral negotiations and offers from recent Integrated Resource Planning (IRP) request for offers (RFO) bid stacks. The Commission should not, however, foreclose other potential vehicles, including additional IOU RFOs or CAISO backstop, to fulfill requirements.

Responses to Questions

6. Are there other expedited processes besides bilateral negotiations or revisiting offers from recent IRP RFO bid stacks that could be used to ensure cost-competitive resources are procured to be online for Summer 2021?

As noted above, the Commission should not foreclose the possibility of expedited RFOs to elicit responses from resources that may not have been previously offered, as some potential sources of cost-effective incremental capacity were not eligible under D.19-11-016. It should further encourage reliance on CAISO backstop when to do so may be more cost-effective or expeditious. Finally, as suggested in response to Question [], the Commission should provide full transparency for project availability by soliciting comments from developers in early January identifying potential projects.

7. Can or should actions be taken to expedite the permitting and interconnection processes associated with this procurement?

No comment.

8. What existing investor-owned electric utility procurement processes (for example, Procurement Review Group consultation independent evaluator oversight, etc.) should be utilized for this procurement?

The Commission should rely on the same procurement processes that will be utilized for Central Procurement Entity (CPE) local RA procurement to ensure that the IOU does not unreasonably favor its resources. The Procurement Review Group (PRG) and the Independent

Evaluator (IE) processes should be the foundation for ensuring the reasonableness of any incremental procurement.

9. What information must be included in any filings seeking final approval from the Commission, including in any potential advice letter filings that might be evaluated and resolved by the Commission's Energy Division?

If the Commission adopts an expedited approval process, it should maximize the transparency of the emergency transactions undertaken on behalf of all LSEs. CalCCA recommends disclosure, at a minimum, of the following transaction details: Counterparty, resource ID, online date and key milestones, milestone penalties, volume, term, hours of availability, impact on the CAM charge, point of interconnection or import intertie, resource type/technology, linkage to incrementality guidelines, whether the price exceeds the price collars, and, if so, the basis for the exceedance; and opportunity for renewal.

10. Are there any additional considerations regarding the procurement process that the Commission should consider in issuing a procurement authorization?

While there are potential efficiencies to be gained from central procurement under the circumstances, there is significant risk that a poorly scoped emergency procurement order could result in market disruption and escalated capacity pricing without achieving its stated goal of increasing capacity available to CAISO. It is critical to consider the role of the procurement order in the context of the broader 2021 RA market and design the procurement order with an eye toward synergy rather than discord.

Specifically, the procurement order must be designed to augment, rather than disrupt, on-going activities by LSEs to procure remaining RA need left from their 2021 Year Ahead RA filings. It is likely that the resources necessary to fulfill LSE RA positions may approach, if not exceed, the available supply of accessible, "in market" RA resources, and the proposed procurement order should anticipate that the vast majority of these resources will come under contract with LSEs prior to the Month Ahead filings, with any remaining known NQC available to CAISO for CPM procurement if absolutely necessary.

The proposed order should, therefore, be narrowly targeted towards the procurement of resources which would not otherwise be procured by LSEs in the normal course of the RA program. Examples of such resources could include:

- Resources which could increase their available NQC with limited physical, legal, or regulatory modifications;
- Resources which could be quickly augmented with additional on-site storage or generating capacity;
- Resources which require multi-year maintenance investments to remain in the RA market;
- Resources which are currently mothballed or otherwise out of service; and
- Import resources.

Failure to properly scope the procurement order could lead to several negative outcomes. First, and most significantly, a poorly scoped order which allows for the procurement of any RA capacity could severely disrupt LSE RA procurement and cannibalize, rather than expand, available RA supply. Take, for example, a procurement order which simply directed IOUs to procure 1,000 MW of RA of any variety. Generators currently engaged in bilateral negotiations with LSEs would immediately consider whether better pricing and terms could be available through the emergency procurement order, slowing LSE negotiations. Assuming LSE RA requirements meet or exceed available supply, any resources siphoned off from these bilateral negotiations would result in a zero-sum reduction in individual LSE showings – leading to no net gain in capacity while increasing the likelihood of LSE deficiencies and exacerbating scarcity pricing.

The policy considerations faced here have strong parallels to the incrementality considerations faced by the Commission in D.19-11-016, and can be best addressed using similar tools. Specifically, the Commission should strive to clearly define and delineate resource eligibility at the outset.

IV. PROCUREMENT COST RECOVERY AND RATEMAKING TREATMENT

Response to Proposal

CalCCA does not agree that the most efficient and cost-effective approach to the problem is IOU central procurement. The CAISO is most intimate with its requirements and the status of generators and thus is in the best position to fill the gap for 2021. In addition, procurement by a single entity that oversees the entire CAISO footprint rather than three entities no doubt will be more efficient. Finally, the CAISO can also better socialize the costs of this procurement among all LSEs in its control area.

If, however, the Commission proceeds with IOU central procurement, CalCCA agrees that, subject to the other comments offered in this response, the CAM is the most suitable cost recovery mechanism.

Response to Question

11. Are there any additional considerations regarding cost recovery and ratemaking treatment the Commission should consider in issuing a procurement authorization?

No comment.

V. PROCESS FOR COMMISSION REVIEW

Response to Proposal.

CalCCA understands the need for an abbreviated approval process to ensure needed resources are available for Summer 2021 but hesitates to support carte blanche action by the IOUs with a Tier 1 Advice Letter process. This expedited process should *only* be adopted if the

Commission maximizes the transparency of the transaction, as described above. CalCCA agrees that a Tier 1 process is not appropriate for UOG resources. Given the range of requirements this procurement will need as guardrails against imprudent procurement, it is most appropriate for the CPUC to retain solid review authority over any procurement.

Response to Question

12. Are there any additional considerations regarding the process for commission review that the Commission should consider in issuing a procurement authorization?

No comment.

VI. CONCLUSION

CalCCA respectfully requests consideration of the responses specified herein and looks forward to an ongoing dialogue with the Commission and stakeholders.

Respectfully submitted,

Evelyn Kahl

Evelyn Kahl
General Counsel to the
California Community Choice Association

December 18, 2020

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Microgrids Pursuant to Senate Bill 1339 and Resiliency Strategies.	)))))	Rulemaking 19-09-009 (Filed September 19, 2019)

COMMENTS OF THE JOINT CCAS
ON THE PROPOSED DECISION

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December 28, 2020

On Behalf Of:
Peninsula Clean Energy Authority
Sonoma Clean Power Authority
Redwood Coast Energy Authority
Pioneer Community Energy
California Choice Energy Authority
Central Coast Community Energy
San Diego Community Power
East Bay Community Energy
Marin Clean Energy

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Microgrids Pursuant to Senate Bill 1339 and Resiliency Strategies.	)))))	Rulemaking 19-09-009 (Filed September 19, 2019)

COMMENTS OF THE JOINT CCAS
ON THE PROPOSED DECISION

In accordance with Rule 14.3 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission") the Joint CCAs[1] hereby submit the following comments on the December 7, 2020 *Proposed Decision of ALJ Rizzo Adopting Rates, Tariffs, And Rules Facilitating The Commercialization of Microgrids Pursuant To Senate Bill 1339 And Resiliency Strategies* ("PD"). The Joint CCAs generally support the PD, as it takes a meaningful step towards the commercialization of microgrids. However, the Joint CCAs have identified several critical corrections and improvements to the PD that are needed to fully achieve this goal. These corrections and improvements are discussed below, with specific recommended modifications to the PD's Conclusions of Law, Findings of Fact, and Ordering Paragraphs provided in Appendix A to these comments.

[1] The Joint CCAs consist of the following Community Choice Aggregation ("CCA") programs: Peninsula Clean Energy Authority ("PCE"); Sonoma Clean Power Authority ("SCP"); Redwood Coast Energy Authority ("RCEA"); Pioneer Community Energy ("Pioneer"); the California Choice Energy Authority ("CalChoice"); Central Coast Community Energy ("3CE"); San Diego Community Power ("SDCP"); East Bay Community Energy ("EBCE"); and Marin Clean Energy ("MCE").

I. COMMENTS ON THE PD'S ADOPTION OF STAFF PROPOSALS

A. Proposal 2: Critical Facility Microgrids on Adjacent Parcels

The PD would require that the IOUs revise their respective Rules 18 (PG&E and SCE) and 19 (SDG&E) to allow customer-sited microgrids that serve critical facilities on adjacent parcels. Under the PD, these Critical Facilities Microgrids ("CFMs") would be required to meet the following requirements:

- The CFM must serve two critical facilities that meet the definition of critical facilities adopted in D.19-05-042;
- The two critical facilities served by the CFM must be owned by a "*municipal corporation*;"
- The two critical facilities served by the CFM must be on adjacent parcels;
- The CFM may only allow Facility A to supply power to Facility B during outages;
- The CFM must include a device that prevents microgrid operation during blue sky conditions.[2]

The Joint CCAs generally support the PD's adoption of a modified version of Proposal 2, Option 2, but recommend that the Commission make four critical corrections and improvements to the PD's CFM proposal. First, the Joint CCAs strongly recommend that the Commission modify the proposal to allow CFMs for critical facilities owned by "public agencies," rather than "municipal corporations." "Municipal corporation" is a term that has varying and somewhat conflicting meanings in California law.[3] While the Joint CCAs do not believe that such interpretations are consistent with the Commission's intent or public safety, under some interpretations the term

[2] PD at 27-33.
[3] 45 Cal. Jur. 3d Municipalities Sections 1-4.

"municipal corporation" may be viewed as excluding critical facilities operated by county, tribal, or state agencies. In order to remove this potential ambiguity, the Joint CCAs recommend that the Commission use the term "public agencies," an open-ended term that includes state, county, local, and tribal agencies rather than "municipal corporations."

Second, the Joint CCAs maintain that the PD's CFM project cap should be either: 1) eliminated entirely; or 2) modified to ensure that the cap does not create an unreasonable and unnecessary barrier to CFM deployment. The PD would cap eligible projects at 10 CFM's in each IOU's service territory (30 CFM projects total).[4] While this is an improvement over the cap proposed in the Staff Proposal, it is still unclear exactly what purpose this cap serves. The PD justifies the cap by asserting that it "establishes guardrails to protect against unintended consequences."[5] While the Joint CCAs appreciate the Commission taking a thoughtful approach to advancing microgrids at CFMs, it does not appear that the record includes any evidence identifying any unintended consequences that could result from CFM deployment, or establishing that unintended consequences, specifically identified or otherwise, are reasonably likely to arise from CFM deployment. To the contrary – given how narrowly CFMs are defined and the fact that only public agencies would operate them, it is difficult to imagine any "out of the blue" unforeseen consequences from CFM deployment, even on a large scale.

To the extent that there exists a small possibility of unforeseen consequences arising, this risk is clearly outweighed by the immediately needed, concrete resiliency benefits that CFMs would provide. It is entirely possible that CFMs, deployed immediately and at scale, could save lives during future outages, especially in the event of "concurrent disasters" such as outages that occur during wildfires.

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[4] PD at 31.

[5] Id.

If, despite these concerns, the Commission believes that a cap is still necessary and appropriate, the Joint CCAs ask that the Commission place strict limits on the cap to ensure that it does not remain a barrier to CFM deployment a moment longer than absolutely necessary. Specifically, the PD should be modified to require that the IOUs file a joint Tier-2 advice letter no later than one month after a total of five CFM projects across all three IOUs' service territories have been operational for six months; and at least 5 CFM projects across all three IOUs' service territories have experienced outages during which one facility shared electricity with the adjacent facility. This advice letter should provide a detailed description of the performance of the CFMs during the outages and identify any "unintended consequences" associated with these projects. If the advice letters do not provide credible evidence of unintended consequences that outweigh the resiliency benefits of CFMs, the cap should automatically expire. If the energy division concludes that the IOUs have provided credible evidence of unintended consequences that outweigh the resiliency benefits, it should require that the IOUs take steps to mitigate these consequences within 6 months, and the cap should expire automatically at the end of this 6-month period.

Third, the PD should be modified to correct an error in its definition of critical facilities. The PD states that only "critical facilities" as defined by the Commission in D.19-05-042 should be eligible for CFMs. The PD rejects requests to expand the definition of "critical facilities" beyond this list because:

> D.19-05-042 directs the IOUs to manage the critical facilities list and processes in partnership with local governments. If parties are seeking to expand the critical facility list and/or modify the processes in partnership with local governments, they should pursue those changes through the avenues contemplated under D.19-05-042—not here. Any deviation from D.19-05-042 through this proceeding would create regulatory confusion and uncertainty.[6]

[6] PD at 32.

The Joint CCAs agree with this legal reasoning, but note that changes to the list of critical facilities "through the avenues contemplated under D.19-05-042" have been raised in the appropriate venue (the De-Energization rulemaking, R.18-12-005), and have been approved by the Commission. Specifically, in D.20-05-051, the Commission expanded the definition of critical facilities to also include public safety answering points (i.e., 911 call centers) and the transportation sector defined as "facilities associated with automobile, rail, aviation, major public transportation and maritime transportation for civilian and military purposes."[7] Thus, the Commission's current official list of critical facilities is the list provided in D.19-05-042 as expanded by D.20-05-051. In order to foster regulatory certainty and avoid confusion, the PD must be updated to appropriately reflect the updated list of critical facilities per D.20-05-051.

Fourth, the Joint CCAs recommend that the Commission clarify the requirement that CFMs operate only during outage conditions and have an installed device that prohibits parallel operation during normal conditions. It is not clear that these requirements serve any *valid* purpose. While the Staff Proposal claims that the requirements are needed "to keep the integrity of not selling power from premise to premise" and to "protect the customer from overcharging,"[8] in the limited context of two critical facilities operated by public agencies, these concerns do not appear to be grounded in reality. There is no legitimate danger of overcharging, as both critical facilities would be operated by public agencies, which are sophisticated actors that do not have a profit motive. Further, both facilities would remain connected to the IOU grid during normal conditions, so there is no danger that one facility would have a monopoly on the power supply to the second, effectively eliminating the possibility of overcharging. Regarding the Staff

7 D.20-05-051, Appendix A at 10.
8 Staff Proposal at 9.

Proposal's concern about "keeping the integrity of not selling power from premise to premise" it is unclear what actual value this integrity provides. PG&E has an existing tariff, the Local Government Renewable Energy Generation Bill Credit Transfer program ("RES-BCT"), that allows local government agencies to use excess renewable generation that is exported to the grid at one site to offset power received from the grid at a second site on a kW-for-kW basis. Allowing CFMs to share excess renewable generation in blue sky conditions would achieve the same purpose, without the added complexity of a generation credit system.

These requirements also do not provide any clear public safety function. To the contrary, – prohibiting microgrid operation during non-outage conditions will significantly reduce the useful value of these microgrids and reduce public agencies' financial incentives (or ability) to deploy them. A CFM with adequate backup generation is a significant investment, as it would have sufficient generation to cover the load of *both* facilities during outages. Under blue sky conditions, the "supplying" facility would have more generation than it needs to serve its own load, and this excess generation would only be able to generate revenue through exports to the grid. In many cases, this model may not make financial sense, as this excess generation would only be used to supply the second facility a few hours or days a year, and the revenue from grid exports will likely not be adequate to offset system costs. Allowing the first facility to supply the second facility with power during blue sky conditions would be a much more financially feasible model. This approach would encourage the adoption of CFMs, the commercializing microgrids generally, and would likely lead to significantly improved public safety impacts.

B. Proposal 3: Adopt a Microgrids Tariff

i. *The Commission Should Clarify The Purpose And Scope Of The Microgrid Tariff*

The Joint CCAs do not categorically oppose the PD's proposed Microgrid Tariff, but believe that this new tariff proposal merits significant additional clarification and refinement.

First, the Joint CCAs believe that the purpose of the tariff should be clarified. The PD purports to adopt the tariff requirement in response to Staff Proposal 3. However, Staff Proposal 3 is a very narrow proposal, and involves only the creation of a tariff for customer-sited, customer-facing, single-parcel microgrids.[9] In contrast, the PD appears to contemplate the tariff serving a much broader purpose, stating that the tariff is intended to "create regulatory identification in the utility' tariff books for a new, statutorily defined entity (a microgrid) pursuant to SB 1339."[10] This confusion carries through to the PD's findings, conclusions, and ordering paragraphs ("OP"), which do not include language clarifying that the tariff applies only to customer-sited, customer-facing, single-parcel microgrids.

This ambiguity raises the concern that the Proposal 3 tariff set forth in the PD would be confused for, or take the place of, an actual comprehensive microgrid tariff (or tariffs) for both customer-sited and utility-sited microgrids. While the CCAs strongly support the creation of a comprehensive microgrid tariff(s), developing such tariffs raises a wide range of complicated issues that need to be fully explored in a robust evidentiary record, and carefully considered by the Commission. These issues include, at a minimum:

- Identifying the resiliency value that various types and configurations of microgrids provide to non-microgrid customers, and compensating microgrid operators for this value;

- Expanding and clarifying the definition of microgrids beyond solar-plus-storage to other technologies including but not limited to fuel cells, biomass, and others;

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9 Staff Proposal at 11 (Table 3-1).
10 PD at 45.

- The most effective ways to facilitate the commercialization of microgrids that serve more than two contiguous parcels and do not cross a street ("Type III Microgrids") and microgrids that cross a street ("Type IV Microgrids").

Parties in Track 2 were instructed to comment on the Staff Proposal, and were not provided an opportunity to directly address these issues. As such, the current record does not include adequate information to make any determination on these issues.

By moving forward with a "microgrids tariff" without record-based resolutions of these key issues, it appears that the PD is attempting to create a structural "placeholder" in the IOU tariff books where a future microgrids tariff can be inserted. As it stands now, the PD provides the IOUs with little guidance regarding the substance of the tariff or the purpose that it is intended to serve (at least as currently structured). For example, if the tariff is limited to Proposal 3 microgrids, it is unclear whether the tariffs would allow for export from customer-sited microgrids beyond the current rules and limitations under the Net Energy Metering ("NEM") tariff (e.g., can the energy storage system export power to the grid even if it were not entirely charged by renewable generation). More fundamentally, it is unclear that an additional tariff is needed – to the extent that the systems involved are NEM systems, NEM is already the authorized tariff. It is unclear what an additional tariff for these systems is intended to do.

The Joint CCAs believe that at this point it is reasonable for the Commission to take two actions: 1) based on the evidentiary record for this proceeding, create a tariff specifically for customer-sited, customer-facing, single- or adjacent-parcel microgrids (type I and II microgrids) and clearly outline in which way this tariff is different from existing NEM rules and requirements; and 2) instruct the IOUs to develop a comprehensive microgrid tariff in Track 3 that addresses type III and IV microgrids. The Commission should also modify its Findings, Conclusions, and OPs to clearly state these requirements.

ii. *The Commission Should Further Clarify CRS And Cost-Shifting Issues To Be Addressed In Track 3*

Proposal 3 of the Staff Proposal raises the question of whether microgrids should be exempt from certain Cost Responsibility Surcharges ("CRS") as compensation for the benefits that microgrids provide to non-microgrid customers. The PD finds that the current evidentiary record is insufficient to resolve this question and defers consideration of the question to Track 3.[11]

While the Joint CCAs believe that it is self-evident that microgrids provide meaningful benefits to non-microgrid customers (especially, for instance, when deployed for resiliency purposes at critical facilities), we agree with the PD that the current evidentiary record is not sufficient to identify all of these benefits, nor is it sufficient to quantify these benefits. As such, the Joint CCAs recommend that the PD be amended to require that the following questions be addressed by the Resiliency and Microgrid Working Group ("RMWG") and incorporated into a future general microgrids tariff:

1. What benefits do microgrids provide non-microgrid customers and the community?
2. Do some microgrid types provide non-microgrid customers with greater benefits than other microgrid types? For example, do microgrids at critical facilities provide greater benefits to non-microgrid customers and the community than microgrids that cover residential or commercial customers? Or do microgrids that serve vulnerable communities provide additional benefits compared to those that serve non-vulnerable populations?

[11] PD at 44.

3. What is the best way to quantify the benefits that microgrids provide to the non-microgrid customers and the community?
4. Should these benefits offset cost recovery surcharges, or should they be accounted for and compensated in a different manner?
5. Are any CRS exemptions needed for microgrid customers to prevent cost shifting from non-microgrid customers to microgrid customers, either generally or for certain microgrid types?

It is worth noting that these questions separate two currently entangled issues – whether microgrids provide value to non-microgrid customers that should be compensated, and whether microgrids should have CRS exemptions. The Joint CCAs believe that these are best addressed as separate questions, with both guided by the principle of avoiding cost shifting in either direction. Tariff principles developed in response to these questions should be incorporated into all applicable microgrid tariffs and sub-tariffs, including the new tariff for customer-sited microgrids created by this PD, any CFM sub-tariff, and any new microgrid tariff for type III and IV microgrids that will be developed in track 3 of this Proceeding.

Given the likelihood that these issues may be contested, and the potential need for complex technical and economic analysis, the Joint CCAs recommend that the PD be modified to direct the energy division to engage a neutral third party to develop an analysis of these questions and provide its analysis to the RMWG and energy division.

C. Proposal 4: Microgrid Incentive Program

The Joint CCAs generally support the PD's microgrid incentive program, but believe that the PD should be amended to provide additional details regarding a number of matters.

i. *The Commission Should Expand On The Purpose Of The Incentives*

The PD should provide more detail regarding the purpose of the incentives being provided, indicating whether the incentives are for generation and/or storage technologies, microgrid equipment like controllers, transmission and distribution upgrades, or all of the above. The staff proposal includes the following as incentive program eligible technologies: generation technology and/or storage technology, microgrid controllers, customer outreach, community costs, reconfiguration of electric service equipment on the customer side of meters (for example to isolate and serve certain loads) and/or on the utility side of meter.[12] The PD also clearly states that SDG&E and SCE are to provide one-time matching funds to cover costs of utility upgrade costs associated with islanding, similar to PG&E's Community Microgrids Enablement Program ("CMEP").[13] This being the case, the Joint CCAs request that the Commission clarify if the incentive program under this proposal specifically addresses project costs that are not covered by, and are in addition to, the utilities' CMEP programs.

ii. *The Commission Should Not Adopt A Scoring System*

Second, the Joint CCAs recommend against the adoption of a scoring system used to prioritize projects under the incentive program for practical reasons. The PD rejects a first-come, first-served approach and instead adopts the California Public Advocates Office's ("CalPA") scoring system proposal.[14] Under this proposal, the IOUs would develop a scoring system based on the following priorities:

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12 Staff proposal at 19.
13 PD at 58.
14 PD at 60.

1. Highest priority – microgrids at critical facilities that lack adequate backup power.

2. Second priority – microgrids serving the highest proportion of medical baseline and electricity-dependent customers

3. Third priority – microgrids serving the highest proportion of access and functional needs customers

4. Fourth priority – microgrids serving the highest proportion of low-income residents, measured by CARE participation/eligibility and a community's CalEnviroScreen score.[15]

The Joint CCAs wholeheartedly support the notion that microgrid development must focus on those customers most vulnerable to outages and those who would experience the most severe impacts from such outages. The Joint CCAs also appreciate the PD's acknowledgement that it is prudent for the Commission to allow microgrids that only meet a portion of the requirements and criteria outlined in Proposal 4 of the Staff Proposal to participate in the incentive program. At the same time, the Joint CCAs question whether the scoring system as proposed is the best way to achieve this goal. As a factual matter, the implementation of a scoring system implies that applications to the incentive program must be received within a certain "application window". Comparing and contrasting, and subsequently scoring applications against each other is only possible if application submission has a set deadline. Applications cannot be submitted on a rolling basis under these parameters. De facto, this would turn the application process to the incentive program more into a "solicitation process" than a typical program application process. The potential downfall of such a process is that projects that miss the application deadline are at a disadvantage and won't be able to participate in the program, thereby leaving potential high-priority projects on the table.

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15 CalPA Opening Comments at 17-18.

Conversely, if there were no application deadline, it would be impossible for the IOUs to evaluate and score the project proposals they receive. What would a utility do if they received a new project with a higher score after they had already confirmed program participation of another project with a lower score? Would the earlier project with the lower score be "kicked out" of the program? Intricately combined with this question is the issue of when/ at what point of the application process the utility would confirm program and incentive allocation to a project. If incentive reservation is not confirmed until the end of the project life-cycle, the financial uncertainty will be a huge impediment for microgrid development. While these are admittedly detailed questions at this early stage, it is critical to address them now – it has been shown in other programs and proceedings that without financial certainty (including incentive certainty), projects will not move forward.

The Joint CCAs also question the need for a scoring system. Especially in the absence of a general tariff for community-scale microgrids and the PD's proposed caps and restrictions on other microgrid types, we very likely won't see the same type of "run" on incentive dollars that we have seen under the Self-Generation Incentive Program ("SGIP").

iii. *The Commission Should Extend The COD Requirement For Incentive Eligibility*

Further, the CCAs question the reasonableness of the PD's December 31, 2022 COD. Based on our experience with other implementation ALs under this proceeding, meeting this deadline will be very challenging.[16] If a final Decision on this issue is issued in February, the Implementation AL wouldn't be filed until June 2021 at the earliest. If there are protests, a disposition of the AL wouldn't be expected until the end of 2021. Then the program has to be established by the utilities (application processes developed, team hired etc.), so realistically the

[16] For example, PG&E's Implementation Advice Letter for the CMEP, which was filed by PG&E on August 17, 2020, is still under Commission review at the time these comments are being filed.

program would only launch in Q2 2022 at the earliest. Given this likely timeline, it is difficult to see how community-scale microgrid projects would be able to meet a COD of December 2022. Alternatively, the Joint CCAs would recommend that project COD should be set at 18 months after the launch of the incentive program.

II. COMMENTS ON SUBSTATION MICROGRIDS

The PD requires that IOU long-term plans for substation microgrids be focused on a transition to clean generation and must be addressed in an Application that includes both a needs assessment and an analysis of wires-based alternatives. The Joint CCAs applaud the Commission for its foresight in imposing these critical requirements.

At the same time, the Joint CCAs have two significant concerns. First, the Joint CCAs are concerned that the PD leaves the IOUs with a significant amount of wiggle room in implementing this transition. For instance, the clean microgrids must be cost-effective, leaving the IOUs with a significant "out." In addition, the PD does not set firm timelines regarding when a transition to cleaner generation must be achieved. Realistically, this could lead to a scenario where there will be significant amounts of fossil-fueled temporary generation (likely diesel) at substations during PSPS transmission outages for the next several years. The PD should be amended to adopt a firm timeline for transitioning away from fossil-fuel temporary generation.

Second, the Joint CCAs are concerned that the PD does not recognize CCAs' exclusive right to provide their customers with generation service within their service areas. In the Track 1 Decision, D.20-06-017, the Commission explicitly recognized the role of CCAs in providing their customers with backup generation, instructing PG&E to coordinate with CCAs on the development of temporary generation-powered substation level microgrids in its service area. The PD should be amended to recognize CCAs' role and further elaborate on CCAs' rights to ensure that temporary generation deployed to serve their customers in their service areas during outage events is consistent with their internal procurement policies and Board-adopted mandates expressing the preferences of their communities.

III. CONCLUSION

The Joint CCAs thank the Commission for their consideration of the matters discussed herein and respectfully request that the Commission adopt the proposed modifications to the PD's Findings of Fact, Conclusions of Law, and Ordering Paragraphs set forth in Appendix A.

Dated: December 28, 2020

Respectfully submitted,

/s/David Peffer

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APPENDIX A

APPENDIX A: APPENDIX OF PROPOSED MODIFICATIONS
(Modifications to existing language are shown as strike outs for deletions and are underlined and boldfaced for additions.)

MODIFICATIONS TO FINDINGS OF FACT:

Modify Finding of Fact 15 as Follows:

~~A subscription limit of ten Rule 18 or Rule 19 microgrid projects per large investor owned electric utility service territory can help limit any unintended,~~ **The record for this proceeding does not establish the likelihood of specific** negative consequences of relaxing some Rule 18 or Rule 19 requirements**, that would outweigh the resiliency benefits of critical facility microgrids, and thus does not justify the adoption of a project subscription cap.**

New Finding of Fact:

Critical facilities are those facilities identified by the Commission as such in D.19-05-042, D.20-05-051, and successor Decisions.

Modify Finding of Fact 17 as Follows:

The record for this proceeding is sufficient to order the ~~Requiring the~~ large investor owned electric utilities to form a new microgrid tariff **for customer-sited, customer-facing, single- or adjacent-parcel microgrids**. ~~establishing a new microgrid rate schedule applicable to net energy metering eligible systems that meet the definition of Senate Bill 1339's microgrid~~ **This tariff** will help commercialize microgrids.

Eliminate Finding of Fact 18:

~~Requiring the large investor owned electric utilities to develop a new microgrid tariff that is explicitly available to microgrids that meet the statutory definition of a microgrid, will help commercialize microgrids.~~

New Finding of Fact:

The record for this proceeding thus far is not sufficient to resolve several basic questions that must be resolved in order to develop a comprehensive microgrids tariff, including, but not limited to, whether one or more types of microgrids should be exempted from one or more CRS, and how the

resiliency and other benefits that microgrids provide to non-microgrid customers should be accounted for and compensated.

New Finding of Fact:

It is reasonable for the Commission to instruct the Resiliency and Microgrids Working Group to develop a proposal or proposals on these issues to be considered in Track 3 of this Rulemaking.

Modify Finding of Fact 29 as Follows:

Resiliency and Microgrid Working Group is best suited for identifying any outstanding microgrid policy issues not adequately addressed by existing venues at the Commission, California Energy Commission, California Air Resources Board, or California Independent System Operator, if any, including but not limited to: (a) attributes or characteristics of microgrids that are not adequately addressed by Rule 21; (b) what impact studies are required for microgrids to connect to the larger electrical grid; and (c) what standards and protocols are needed to meet large investor owned electrical corporation and California Independent System Operator requirements. **These issues should be addressed by the Commission in Track 3 of this Rulemaking as part of its development of a comprehensive microgrids tariff.**

MODIFICATIONS TO CONCLUSIONS OF LAW:

Modify Conclusion of Law 14:

It is reasonable to require Pacific Gas and Electric Company and Southern California Edison Company to revise their respective electric tariff Rule 18, and San Diego Gas & Electric Company to revise its electric tariff Rule 19, to allow ~~municipal corporation~~ **public agency** microgrids to serve ~~municipal~~ critical facilities on adjacent parcels.

Modify Conclusion of Law 15:

It is reasonable to require Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas& Electric Company to ensure that Rule 18 and Rule 19 microgrids that serve critical customers on adjacent premises are ownership agnostic so ~~municipal corporations~~ **public agencies** have more flexibility to develop a microgrid project that can supply electricity to adjacent premises during an emergency and/or support critical operations during a grid outage.

New Conclusion of Law:

Critical Facilities include all facilities defined as such in D.19-05-042, D.20-05-051, and any subsequent Commission decisions in the De-Energization Rulemaking or any successor proceeding.

New Conclusion of Law:

It is reasonable to allow Critical Facility Microgrids to exchange electricity between the two sites during blue sky conditions as long as both sites continue operating in parallel to the grid.

Eliminate Conclusion of Law 16:

~~It is reasonable to require Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company to implement a subscription limit of ten microgrid projects for each service territory to reflect the Rule 18 and Rule 19 revisions.~~

New Conclusion of Law:

It is not reasonable to impose a project cap on critical facility microgrids, as the record does not establish that the risk of specific unintended consequences outweighs the resiliency benefits that critical facility microgrids can provide.

Modify Conclusion of Law 17:

It is reasonable to require Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company to form a new microgrid tariff **for customer-sited, customer-facing, single- or adjacent-parcel microgrids** pursuant to Section 3.3.3 of this decision.

New Conclusion of Law:

The Resiliency and Microgrid Working Group should consider and develop proposals for the development of a comprehensive microgrid tariff. These proposals should be considered, and a comprehensive tariff adopted by the Commission in Track 3 of this rulemaking.

New Conclusion of Law:

<u>It is not reasonable for the Commission to require that incentive program funds be distributed using a scoring system.</u>

New Conclusion of Law:

<u>It is reasonable for the Commission to require incentive program funds be directed to projects with a COD of 18 months after the launch of the incentive program.</u>

New Conclusion of Law:

<u>CCAs have the exclusive right to provide their customers with generation service within their generation area. All IOU backup generation projects that will serve CCA customers must be developed in coordination with the relevant CCA. This coordination must occur at all phases of the planning process.</u>

<u>MODIFICATIONS TO ORDERING PARAGRAPHS:</u>

Modify Ordering Paragraph 2:

Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall each file a Tier 2 advice letter, within 30 days upon the issuance of this decision, implementing Rule 18 and Rule 19 revisions pursuant to Section 3.2.3 of this decision. In this Tier 2 advice letter, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall each explicitly state that microgrids owned by ~~municipal corporations~~ **<u>public agencies</u>** or by a third party that primarily serves facilities owned or operated by, or on behalf of, a ~~municipal corporation~~ **<u>public agency</u>** are permitted to supply electricity to critical facilities owned or operated by or on behalf of a ~~municipal corporation~~ **<u>public agency</u>** on an adjacent premises. In this Tier 2 advice letter, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas &Electric Company shall each also form a pathway for the Rule 18 or Rule 19 microgrid projects to become live, ~~and shall adhere to the subscription limit of 10 microgrid projects for each service territory pursuant to Section 3.2.3 of this decision~~.

Modify Ordering Paragraph 3:

Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall each file a Tier 2 advice letter, within 90 days upon issuance of this decision, that forms a new microgrid tariff **<u>for</u>**

customer-sited, customer-facing, single- or adjacent-parcel microgrids pursuant to Section 3.3.3 of this decision. In this Tier 2 advice letter, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall each:

- Create a new microgrid rate schedule within each of the IOUs electric tariffs applicable to **customer-sited, customer-facing, single- or adjacent-parcel microgrid** systems that: (a) meets the definition of microgrid contained in Senate Bill 1339; (b) is interconnected under the terms of Electric Rule 21; and (c) consists of resources that are individually eligible for a net energy metering successor schedule that reflects the orders in Decision 16-01-044;
- Without changing or redefining terms, incorporates applicable existing tariffs into the new microgrid rate schedule by reference;
- Incorporates new microgrid rate schedule into the resiliency project engagement guide required by Decision 20-06-017, Ordering Paragraph 9; and
- Incorporates new rate schedule into all other relevant materials, including any websites or portals, where other related rate schedules are presented.

Modify Ordering Paragraph 9:

Energy Division shall facilitate the Resiliency and Microgrids Working Group, which shall identify microgrid-specific policy issues that are not adequately addressed by existing venues at the Commission, California Energy Commission, California Air Resources Board, or California Independent System Operator, if any, including but not limited to:

[List Omitted]

The Working Group shall develop proposals on major unresolved issues related to the deployment of a comprehensive microgrid tariff for Commission consideration in Track 3 of this rulemaking.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Microgrids Pursuant to Senate Bill 1339 and Resiliency Strategies.	)))))	Rulemaking 19-09-009 (Filed September 19, 2019)

COMMENTS OF THE JOINT CCAS
ON THE PROPOSED DECISION

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December 28, 2020

On Behalf Of:
Peninsula Clean Energy Authority
Sonoma Clean Power Authority
Redwood Coast Energy Authority
Pioneer Community Energy
California Choice Energy Authority
Central Coast Community Energy
San Diego Community Power
East Bay Community Energy
Marin Clean Energy

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Microgrids Pursuant to Senate Bill 1339 and Resiliency Strategies.	)))))	Rulemaking 19-09-009 (Filed September 19, 2019)

COMMENTS OF THE JOINT CCAS
ON THE PROPOSED DECISION

In accordance with Rule 14.3 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission") the Joint CCAs[1] hereby submit the following comments on the December 7, 2020 *Proposed Decision of ALJ Rizzo Adopting Rates, Tariffs, And Rules Facilitating The Commercialization of Microgrids Pursuant To Senate Bill 1339 And Resiliency Strategies* ("PD"). The Joint CCAs generally support the PD, as it takes a meaningful step towards the commercialization of microgrids. However, the Joint CCAs have identified several critical corrections and improvements to the PD that are needed to fully achieve this goal. These corrections and improvements are discussed below, with specific recommended modifications to the PD's Conclusions of Law, Findings of Fact, and Ordering Paragraphs provided in Appendix A to these comments.

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[1] The Joint CCAs consist of the following Community Choice Aggregation ("CCA") programs: Peninsula Clean Energy Authority ("PCE"); Sonoma Clean Power Authority ("SCP"); Redwood Coast Energy Authority ("RCEA"); Pioneer Community Energy ("Pioneer"); the California Choice Energy Authority ("CalChoice"); Central Coast Community Energy ("3CE"); San Diego Community Power ("SDCP"); East Bay Community Energy ("EBCE"); and Marin Clean Energy ("MCE").

I. COMMENTS ON THE PD'S ADOPTION OF STAFF PROPOSALS

A. Proposal 2: Critical Facility Microgrids on Adjacent Parcels

The PD would require that the IOUs revise their respective Rules 18 (PG&E and SCE) and 19 (SDG&E) to allow customer-sited microgrids that serve critical facilities on adjacent parcels. Under the PD, these Critical Facilities Microgrids ("CFMs") would be required to meet the following requirements:

- The CFM must serve two critical facilities that meet the definition of critical facilities adopted in D.19-05-042;
- The two critical facilities served by the CFM must be owned by a "*municipal corporation*;"
- The two critical facilities served by the CFM must be on adjacent parcels;
- The CFM may only allow Facility A to supply power to Facility B during outages;
- The CFM must include a device that prevents microgrid operation during blue sky conditions.[2]

The Joint CCAs generally support the PD's adoption of a modified version of Proposal 2, Option 2, but recommend that the Commission make four critical corrections and improvements to the PD's CFM proposal. First, the Joint CCAs strongly recommend that the Commission modify the proposal to allow CFMs for critical facilities owned by "public agencies," rather than "municipal corporations." "Municipal corporation" is a term that has varying and somewhat conflicting meanings in California law.[3] While the Joint CCAs do not believe that such interpretations are consistent with the Commission's intent or public safety, under some interpretations the term

[2] PD at 27-33.
[3] 45 Cal. Jur. 3d Municipalities Sections 1-4.

"municipal corporation" may be viewed as excluding critical facilities operated by county, tribal, or state agencies. In order to remove this potential ambiguity, the Joint CCAs recommend that the Commission use the term "public agencies," an open-ended term that includes state, county, local, and tribal agencies rather than "municipal corporations."

Second, the Joint CCAs maintain that the PD's CFM project cap should be either: 1) eliminated entirely; or 2) modified to ensure that the cap does not create an unreasonable and unnecessary barrier to CFM deployment. The PD would cap eligible projects at 10 CFM's in each IOU's service territory (30 CFM projects total).[4] While this is an improvement over the cap proposed in the Staff Proposal, it is still unclear exactly what purpose this cap serves. The PD justifies the cap by asserting that it "establishes guardrails to protect against unintended consequences."[5] While the Joint CCAs appreciate the Commission taking a thoughtful approach to advancing microgrids at CFMs, it does not appear that the record includes any evidence identifying any unintended consequences that could result from CFM deployment, or establishing that unintended consequences, specifically identified or otherwise, are reasonably likely to arise from CFM deployment. To the contrary – given how narrowly CFMs are defined and the fact that only public agencies would operate them, it is difficult to imagine any "out of the blue" unforeseen consequences from CFM deployment, even on a large scale.

To the extent that there exists a small possibility of unforeseen consequences arising, this risk is clearly outweighed by the immediately needed, concrete resiliency benefits that CFMs would provide. It is entirely possible that CFMs, deployed immediately and at scale, could save lives during future outages, especially in the event of "concurrent disasters" such as outages that occur during wildfires.

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4 PD at 31.

5 Id.

If, despite these concerns, the Commission believes that a cap is still necessary and appropriate, the Joint CCAs ask that the Commission place strict limits on the cap to ensure that it does not remain a barrier to CFM deployment a moment longer than absolutely necessary. Specifically, the PD should be modified to require that the IOUs file a joint Tier-2 advice letter no later than one month after a total of five CFM projects across all three IOUs' service territories have been operational for six months; and at least 5 CFM projects across all three IOUs' service territories have experienced outages during which one facility shared electricity with the adjacent facility. This advice letter should provide a detailed description of the performance of the CFMs during the outages and identify any "unintended consequences" associated with these projects. If the advice letters do not provide credible evidence of unintended consequences that outweigh the resiliency benefits of CFMs, the cap should automatically expire. If the energy division concludes that the IOUs have provided credible evidence of unintended consequences that outweigh the resiliency benefits, it should require that the IOUs take steps to mitigate these consequences within 6 months, and the cap should expire automatically at the end of this 6-month period.

Third, the PD should be modified to correct an error in its definition of critical facilities. The PD states that only "critical facilities" as defined by the Commission in D.19-05-042 should be eligible for CFMs. The PD rejects requests to expand the definition of "critical facilities" beyond this list because:

> D.19-05-042 directs the IOUs to manage the critical facilities list and processes in partnership with local governments. If parties are seeking to expand the critical facility list and/or modify the processes in partnership with local governments, they should pursue those changes through the avenues contemplated under D.19-05-042—not here. Any deviation from D.19-05-042 through this proceeding would create regulatory confusion and uncertainty.[6]

[6] PD at 32.

The Joint CCAs agree with this legal reasoning, but note that changes to the list of critical facilities "through the avenues contemplated under D.19-05-042" have been raised in the appropriate venue (the De-Energization rulemaking, R.18-12-005), and have been approved by the Commission. Specifically, in D.20-05-051, the Commission expanded the definition of critical facilities to also include public safety answering points (i.e., 911 call centers) and the transportation sector defined as "facilities associated with automobile, rail, aviation, major public transportation and maritime transportation for civilian and military purposes."[7] Thus, the Commission's current official list of critical facilities is the list provided in D.19-05-042 as expanded by D.20-05-051. In order to foster regulatory certainty and avoid confusion, the PD must be updated to appropriately reflect the updated list of critical facilities per D.20-05-051.

Fourth, the Joint CCAs recommend that the Commission clarify the requirement that CFMs operate only during outage conditions and have an installed device that prohibits parallel operation during normal conditions. It is not clear that these requirements serve any *valid* purpose. While the Staff Proposal claims that the requirements are needed "to keep the integrity of not selling power from premise to premise" and to "protect the customer from overcharging,"[8] in the limited context of two critical facilities operated by public agencies, these concerns do not appear to be grounded in reality. There is no legitimate danger of overcharging, as both critical facilities would be operated by public agencies, which are sophisticated actors that do not have a profit motive. Further, both facilities would remain connected to the IOU grid during normal conditions, so there is no danger that one facility would have a monopoly on the power supply to the second, effectively eliminating the possibility of overcharging. Regarding the Staff

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7 D.20-05-051, Appendix A at 10.

8 Staff Proposal at 9.

Proposal's concern about "keeping the integrity of not selling power from premise to premise" it is unclear what actual value this integrity provides. PG&E has an existing tariff, the Local Government Renewable Energy Generation Bill Credit Transfer program ("RES-BCT"), that allows local government agencies to use excess renewable generation that is exported to the grid at one site to offset power received from the grid at a second site on a kW-for-kW basis. Allowing CFMs to share excess renewable generation in blue sky conditions would achieve the same purpose, without the added complexity of a generation credit system.

These requirements also do not provide any clear public safety function. To the contrary, – prohibiting microgrid operation during non-outage conditions will significantly reduce the useful value of these microgrids and reduce public agencies' financial incentives (or ability) to deploy them. A CFM with adequate backup generation is a significant investment, as it would have sufficient generation to cover the load of *both* facilities during outages. Under blue sky conditions, the "supplying" facility would have more generation than it needs to serve its own load, and this excess generation would only be able to generate revenue through exports to the grid. In many cases, this model may not make financial sense, as this excess generation would only be used to supply the second facility a few hours or days a year, and the revenue from grid exports will likely not be adequate to offset system costs. Allowing the first facility to supply the second facility with power during blue sky conditions would be a much more financially feasible model. This approach would encourage the adoption of CFMs, the commercializing microgrids generally, and would likely lead to significantly improved public safety impacts.

B. Proposal 3: Adopt a Microgrids Tariff

i. *The Commission Should Clarify The Purpose And Scope Of The Microgrid Tariff*

The Joint CCAs do not categorically oppose the PD's proposed Microgrid Tariff, but believe that this new tariff proposal merits significant additional clarification and refinement.

First, the Joint CCAs believe that the purpose of the tariff should be clarified. The PD purports to adopt the tariff requirement in response to Staff Proposal 3. However, Staff Proposal 3 is a very narrow proposal, and involves only the creation of a tariff for customer-sited, customer-facing, single-parcel microgrids.[9] In contrast, the PD appears to contemplate the tariff serving a much broader purpose, stating that the tariff is intended to "create regulatory identification in the utility' tariff books for a new, statutorily defined entity (a microgrid) pursuant to SB 1339."[10] This confusion carries through to the PD's findings, conclusions, and ordering paragraphs ("OP"), which do not include language clarifying that the tariff applies only to customer-sited, customer-facing, single-parcel microgrids.

This ambiguity raises the concern that the Proposal 3 tariff set forth in the PD would be confused for, or take the place of, an actual comprehensive microgrid tariff (or tariffs) for both customer-sited and utility-sited microgrids. While the CCAs strongly support the creation of a comprehensive microgrid tariff(s), developing such tariffs raises a wide range of complicated issues that need to be fully explored in a robust evidentiary record, and carefully considered by the Commission. These issues include, at a minimum:

- Identifying the resiliency value that various types and configurations of microgrids provide to non-microgrid customers, and compensating microgrid operators for this value;
- Expanding and clarifying the definition of microgrids beyond solar-plus-storage to other technologies including but not limited to fuel cells, biomass, and others;

9 Staff Proposal at 11 (Table 3-1).
10 PD at 45.

- The most effective ways to facilitate the commercialization of microgrids that serve more than two contiguous parcels and do not cross a street ("Type III Microgrids") and microgrids that cross a street ("Type IV Microgrids").

Parties in Track 2 were instructed to comment on the Staff Proposal, and were not provided an opportunity to directly address these issues. As such, the current record does not include adequate information to make any determination on these issues.

By moving forward with a "microgrids tariff" without record-based resolutions of these key issues, it appears that the PD is attempting to create a structural "placeholder" in the IOU tariff books where a future microgrids tariff can be inserted. As it stands now, the PD provides the IOUs with little guidance regarding the substance of the tariff or the purpose that it is intended to serve (at least as currently structured). For example, if the tariff is limited to Proposal 3 microgrids, it is unclear whether the tariffs would allow for export from customer-sited microgrids beyond the current rules and limitations under the Net Energy Metering ("NEM") tariff (e.g., can the energy storage system export power to the grid even if it were not entirely charged by renewable generation). More fundamentally, it is unclear that an additional tariff is needed – to the extent that the systems involved are NEM systems, NEM is already the authorized tariff. It is unclear what an additional tariff for these systems is intended to do.

The Joint CCAs believe that at this point it is reasonable for the Commission to take two actions: 1) based on the evidentiary record for this proceeding, create a tariff specifically for customer-sited, customer-facing, single- or adjacent-parcel microgrids (type I and II microgrids) and clearly outline in which way this tariff is different from existing NEM rules and requirements; and 2) instruct the IOUs to develop a comprehensive microgrid tariff in Track 3 that addresses type III and IV microgrids. The Commission should also modify its Findings, Conclusions, and OPs to clearly state these requirements.

ii. *The Commission Should Further Clarify CRS And Cost-Shifting Issues To Be Addressed In Track 3*

Proposal 3 of the Staff Proposal raises the question of whether microgrids should be exempt from certain Cost Responsibility Surcharges ("CRS") as compensation for the benefits that microgrids provide to non-microgrid customers. The PD finds that the current evidentiary record is insufficient to resolve this question and defers consideration of the question to Track 3.[11]

While the Joint CCAs believe that it is self-evident that microgrids provide meaningful benefits to non-microgrid customers (especially, for instance, when deployed for resiliency purposes at critical facilities), we agree with the PD that the current evidentiary record is not sufficient to identify all of these benefits, nor is it sufficient to quantify these benefits. As such, the Joint CCAs recommend that the PD be amended to require that the following questions be addressed by the Resiliency and Microgrid Working Group ("RMWG") and incorporated into a future general microgrids tariff:

1. What benefits do microgrids provide non-microgrid customers and the community?
2. Do some microgrid types provide non-microgrid customers with greater benefits than other microgrid types? For example, do microgrids at critical facilities provide greater benefits to non-microgrid customers and the community than microgrids that cover residential or commercial customers? Or do microgrids that serve vulnerable communities provide additional benefits compared to those that serve non-vulnerable populations?

11 PD at 44.

3. What is the best way to quantify the benefits that microgrids provide to the non-microgrid customers and the community?
4. Should these benefits offset cost recovery surcharges, or should they be accounted for and compensated in a different manner?
5. Are any CRS exemptions needed for microgrid customers to prevent cost shifting from non-microgrid customers to microgrid customers, either generally or for certain microgrid types?

It is worth noting that these questions separate two currently entangled issues – whether microgrids provide value to non-microgrid customers that should be compensated, and whether microgrids should have CRS exemptions. The Joint CCAs believe that these are best addressed as separate questions, with both guided by the principle of avoiding cost shifting in either direction. Tariff principles developed in response to these questions should be incorporated into all applicable microgrid tariffs and sub-tariffs, including the new tariff for customer-sited microgrids created by this PD, any CFM sub-tariff, and any new microgrid tariff for type III and IV microgrids that will be developed in track 3 of this Proceeding.

Given the likelihood that these issues may be contested, and the potential need for complex technical and economic analysis, the Joint CCAs recommend that the PD be modified to direct the energy division to engage a neutral third party to develop an analysis of these questions and provide its analysis to the RMWG and energy division.

C. Proposal 4: Microgrid Incentive Program

The Joint CCAs generally support the PD's microgrid incentive program, but believe that the PD should be amended to provide additional details regarding a number of matters.

i. *The Commission Should Expand On The Purpose Of The Incentives*

The PD should provide more detail regarding the purpose of the incentives being provided, indicating whether the incentives are for generation and/or storage technologies, microgrid equipment like controllers, transmission and distribution upgrades, or all of the above. The staff proposal includes the following as incentive program eligible technologies: generation technology and/or storage technology, microgrid controllers, customer outreach, community costs, reconfiguration of electric service equipment on the customer side of meters (for example to isolate and serve certain loads) and/or on the utility side of meter.[12] The PD also clearly states that SDG&E and SCE are to provide one-time matching funds to cover costs of utility upgrade costs associated with islanding, similar to PG&E's Community Microgrids Enablement Program ("CMEP").[13] This being the case, the Joint CCAs request that the Commission clarify if the incentive program under this proposal specifically addresses project costs that are not covered by, and are in addition to, the utilities' CMEP programs.

ii. *The Commission Should Not Adopt A Scoring System*

Second, the Joint CCAs recommend against the adoption of a scoring system used to prioritize projects under the incentive program for practical reasons. The PD rejects a first-come, first-served approach and instead adopts the California Public Advocates Office's ("CalPA") scoring system proposal.[14] Under this proposal, the IOUs would develop a scoring system based on the following priorities:

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[12] Staff proposal at 19.
[13] PD at 58.
[14] PD at 60.

1. Highest priority – microgrids at critical facilities that lack adequate backup power.

2. Second priority – microgrids serving the highest proportion of medical baseline and electricity-dependent customers

3. Third priority – microgrids serving the highest proportion of access and functional needs customers

4. Fourth priority – microgrids serving the highest proportion of low-income residents, measured by CARE participation/eligibility and a community's CalEnviroScreen score.[15]

The Joint CCAs wholeheartedly support the notion that microgrid development must focus on those customers most vulnerable to outages and those who would experience the most severe impacts from such outages. The Joint CCAs also appreciate the PD's acknowledgement that it is prudent for the Commission to allow microgrids that only meet a portion of the requirements and criteria outlined in Proposal 4 of the Staff Proposal to participate in the incentive program. At the same time, the Joint CCAs question whether the scoring system as proposed is the best way to achieve this goal. As a factual matter, the implementation of a scoring system implies that applications to the incentive program must be received within a certain "application window". Comparing and contrasting, and subsequently scoring applications against each other is only possible if application submission has a set deadline. Applications cannot be submitted on a rolling basis under these parameters. De facto, this would turn the application process to the incentive program more into a "solicitation process" than a typical program application process. The potential downfall of such a process is that projects that miss the application deadline are at a disadvantage and won't be able to participate in the program, thereby leaving potential high-priority projects on the table.

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[15] CalPA Opening Comments at 17-18.

Conversely, if there were no application deadline, it would be impossible for the IOUs to evaluate and score the project proposals they receive. What would a utility do if they received a new project with a higher score after they had already confirmed program participation of another project with a lower score? Would the earlier project with the lower score be "kicked out" of the program? Intricately combined with this question is the issue of when/ at what point of the application process the utility would confirm program and incentive allocation to a project. If incentive reservation is not confirmed until the end of the project life-cycle, the financial uncertainty will be a huge impediment for microgrid development. While these are admittedly detailed questions at this early stage, it is critical to address them now – it has been shown in other programs and proceedings that without financial certainty (including incentive certainty), projects will not move forward.

The Joint CCAs also question the need for a scoring system. Especially in the absence of a general tariff for community-scale microgrids and the PD's proposed caps and restrictions on other microgrid types, we very likely won't see the same type of "run" on incentive dollars that we have seen under the Self-Generation Incentive Program ("SGIP").

iii. *The Commission Should Extend The COD Requirement For Incentive Eligibility*

Further, the CCAs question the reasonableness of the PD's December 31, 2022 COD. Based on our experience with other implementation ALs under this proceeding, meeting this deadline will be very challenging.[16] If a final Decision on this issue is issued in February, the Implementation AL wouldn't be filed until June 2021 at the earliest. If there are protests, a disposition of the AL wouldn't be expected until the end of 2021. Then the program has to be established by the utilities (application processes developed, team hired etc.), so realistically the

[16] For example, PG&E's Implementation Advice Letter for the CMEP, which was filed by PG&E on August 17, 2020, is still under Commission review at the time these comments are being filed.

program would only launch in Q2 2022 at the earliest. Given this likely timeline, it is difficult to see how community-scale microgrid projects would be able to meet a COD of December 2022. Alternatively, the Joint CCAs would recommend that project COD should be set at 18 months after the launch of the incentive program.

II. COMMENTS ON SUBSTATION MICROGRIDS

The PD requires that IOU long-term plans for substation microgrids be focused on a transition to clean generation and must be addressed in an Application that includes both a needs assessment and an analysis of wires-based alternatives. The Joint CCAs applaud the Commission for its foresight in imposing these critical requirements.

At the same time, the Joint CCAs have two significant concerns. First, the Joint CCAs are concerned that the PD leaves the IOUs with a significant amount of wiggle room in implementing this transition. For instance, the clean microgrids must be cost-effective, leaving the IOUs with a significant "out." In addition, the PD does not set firm timelines regarding when a transition to cleaner generation must be achieved. Realistically, this could lead to a scenario where there will be significant amounts of fossil-fueled temporary generation (likely diesel) at substations during PSPS transmission outages for the next several years. The PD should be amended to adopt a firm timeline for transitioning away from fossil-fuel temporary generation.

Second, the Joint CCAs are concerned that the PD does not recognize CCAs' exclusive right to provide their customers with generation service within their service areas. In the Track 1 Decision, D.20-06-017, the Commission explicitly recognized the role of CCAs in providing their customers with backup generation, instructing PG&E to coordinate with CCAs on the development of temporary generation-powered substation level microgrids in its service area. The PD should be amended to recognize CCAs' role and further elaborate on CCAs' rights to ensure that temporary generation deployed to serve their customers in their service areas during outage events is consistent with their internal procurement policies and Board-adopted mandates expressing the preferences of their communities.

III. CONCLUSION

The Joint CCAs thank the Commission for their consideration of the matters discussed herein and respectfully request that the Commission adopt the proposed modifications to the PD's Findings of Fact, Conclusions of Law, and Ordering Paragraphs set forth in Appendix A.

Dated: December 28, 2020

Respectfully submitted,

/s/David Peffer

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Sonoma Clean Power Authority
Redwood Coast Energy Authority
Pioneer Community Energy
California Choice Energy Authority
Central Coast Community Energy
San Diego Community Power
East Bay Community Energy
Marin Clean Energy

APPENDIX A

APPENDIX A: APPENDIX OF PROPOSED MODIFICATIONS
(Modifications to existing language are shown as strike outs for deletions and are underlined and boldfaced for additions.)

MODIFICATIONS TO FINDINGS OF FACT:

Modify Finding of Fact 15 as Follows:

~~A subscription limit of ten Rule 18 or Rule 19 microgrid projects per large investor owned electric utility service territory can help limit any unintended,~~ **The record for this proceeding does not establish the likelihood of specific** negative consequences of relaxing some Rule 18 or Rule 19 requirements**, that would outweigh the resiliency benefits of critical facility microgrids, and thus does not justify the adoption of a project subscription cap.**

New Finding of Fact:

Critical facilities are those facilities identified by the Commission as such in D.19-05-042, D.20-05-051, and successor Decisions.

Modify Finding of Fact 17 as Follows:

The record for this proceeding is sufficient to order the ~~Requiring the~~ large investor owned electric utilities to form a new microgrid tariff **for customer-sited, customer-facing, single- or adjacent-parcel microgrids**. ~~establishing a new microgrid rate schedule applicable to net energy metering eligible systems that meet the definition of Senate Bill 1339's microgrid~~ **This tariff** will help commercialize microgrids.

Eliminate Finding of Fact 18:

~~Requiring the large investor owned electric utilities to develop a new microgrid tariff that is explicitly available to microgrids that meet the statutory definition of a microgrid, will help commercialize microgrids.~~

New Finding of Fact:

The record for this proceeding thus far is not sufficient to resolve several basic questions that must be resolved in order to develop a comprehensive microgrids tariff, including, but not limited to, whether one or more types of microgrids should be exempted from one or more CRS, and how the

<u>resiliency and other benefits that microgrids provide to non-microgrid customers should be accounted for and compensated.</u>

New Finding of Fact:

<u>It is reasonable for the Commission to instruct the Resiliency and Microgrids Working Group to develop a proposal or proposals on these issues to be considered in Track 3 of this Rulemaking.</u>

Modify Finding of Fact 29 as Follows:

Resiliency and Microgrid Working Group is best suited for identifying any outstanding microgrid policy issues not adequately addressed by existing venues at the Commission, California Energy Commission, California Air Resources Board, or California Independent System Operator, if any, including but not limited to: (a) attributes or characteristics of microgrids that are not adequately addressed by Rule 21; (b) what impact studies are required for microgrids to connect to the larger electrical grid; and (c) what standards and protocols are needed to meet large investor owned electrical corporation and California Independent System Operator requirements. **<u>These issues should be addressed by the Commission in Track 3 of this Rulemaking as part of its development of a comprehensive microgrids tariff.</u>**

<u>*MODIFICATIONS TO CONCLUSIONS OF LAW:*</u>

Modify Conclusion of Law 14:

It is reasonable to require Pacific Gas and Electric Company and Southern California Edison Company to revise their respective electric tariff Rule 18, and San Diego Gas & Electric Company to revise its electric tariff Rule 19, to allow ~~municipal corporation~~ **<u>public agency</u>** microgrids to serve ~~municipal~~ critical facilities on adjacent parcels.

Modify Conclusion of Law 15:

It is reasonable to require Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas& Electric Company to ensure that Rule 18 and Rule 19 microgrids that serve critical customers on adjacent premises are ownership agnostic so ~~municipal~~ ~~corporations~~ **<u>public agencies</u>** have more flexibility to develop a microgrid project that can supply electricity to adjacent premises during an emergency and/or support critical operations during a grid outage.

New Conclusion of Law:

Critical Facilities include all facilities defined as such in D.19-05-042, D.20-05-051, and any subsequent Commission decisions in the De-Energization Rulemaking or any successor proceeding.

New Conclusion of Law:

It is reasonable to allow Critical Facility Microgrids to exchange electricity between the two sites during blue sky conditions as long as both sites continue operating in parallel to the grid.

Eliminate Conclusion of Law 16:

~~It is reasonable to require Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company to implement a subscription limit of ten microgrid projects for each service territory to reflect the Rule 18 and Rule 19 revisions.~~

New Conclusion of Law:

It is not reasonable to impose a project cap on critical facility microgrids, as the record does not establish that the risk of specific unintended consequences outweighs the resiliency benefits that critical facility microgrids can provide.

Modify Conclusion of Law 17:

It is reasonable to require Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company to form a new microgrid tariff **for customer-sited, customer-facing, single- or adjacent-parcel microgrids** pursuant to Section 3.3.3 of this decision.

New Conclusion of Law:

The Resiliency and Microgrid Working Group should consider and develop proposals for the development of a comprehensive microgrid tariff. These proposals should be considered, and a comprehensive tariff adopted by the Commission in Track 3 of this rulemaking.

New Conclusion of Law:

<u>It is not reasonable for the Commission to require that incentive program funds be distributed using a scoring system.</u>

New Conclusion of Law:

<u>It is reasonable for the Commission to require incentive program funds be directed to projects with a COD of 18 months after the launch of the incentive program.</u>

New Conclusion of Law:

<u>CCAs have the exclusive right to provide their customers with generation service within their generation area. All IOU backup generation projects that will serve CCA customers must be developed in coordination with the relevant CCA. This coordination must occur at all phases of the planning process.</u>

<u>MODIFICATIONS TO ORDERING PARAGRAPHS:</u>

Modify Ordering Paragraph 2:

Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall each file a Tier 2 advice letter, within 30 days upon the issuance of this decision, implementing Rule 18 and Rule 19 revisions pursuant to Section 3.2.3 of this decision. In this Tier 2 advice letter, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall each explicitly state that microgrids owned by ~~municipal corporations~~ **<u>public agencies</u>** or by a third party that primarily serves facilities owned or operated by, or on behalf of, a ~~municipal corporation~~ **<u>public agency</u>** are permitted to supply electricity to critical facilities owned or operated by or on behalf of a ~~municipal corporation~~ **<u>public agency</u>** on an adjacent premises. In this Tier 2 advice letter, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas &Electric Company shall each also form a pathway for the Rule 18 or Rule 19 microgrid projects to become live, ~~and shall adhere to the subscription limit of 10 microgrid projects for each service territory pursuant to Section 3.2.3 of this decision~~.

Modify Ordering Paragraph 3:

Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall each file a Tier 2 advice letter, within 90 days upon issuance of this decision, that forms a new microgrid tariff **<u>for</u>**

customer-sited, customer-facing, single- or adjacent-parcel microgrids pursuant to Section 3.3.3 of this decision. In this Tier 2 advice letter, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall each:

- Create a new microgrid rate schedule within each of the IOUs electric tariffs applicable to **customer-sited, customer-facing, single- or adjacent-parcel microgrid** systems that: (a) meets the definition of microgrid contained in Senate Bill 1339; (b) is interconnected under the terms of Electric Rule 21; and (c) consists of resources that are individually eligible for a net energy metering successor schedule that reflects the orders in Decision 16-01-044;
- Without changing or redefining terms, incorporates applicable existing tariffs into the new microgrid rate schedule by reference;
- Incorporates new microgrid rate schedule into the resiliency project engagement guide required by Decision 20-06-017, Ordering Paragraph 9; and
- Incorporates new rate schedule into all other relevant materials, including any websites or portals, where other related rate schedules are presented.

Modify Ordering Paragraph 9:

Energy Division shall facilitate the Resiliency and Microgrids Working Group, which shall identify microgrid-specific policy issues that are not adequately addressed by existing venues at the Commission, California Energy Commission, California Air Resources Board, or California Independent System Operator, if any, including but not limited to:

[List Omitted]

The Working Group shall develop proposals on major unresolved issues related to the deployment of a comprehensive microgrid tariff for Commission consideration in Track 3 of this rulemaking.

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.	Rulemaking 18-07-003 (Filed July 12, 2018)

COMMENTS OF MARIN CLEAN ENERGY ON PROPOSED DECISION

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December 29, 2020

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MCE Has Met Long-Term Contracting Requirements

- MCE has achieved the 65% long-term contracting requirement for the 2021-2024. Existing MCE supply commitments place MCE in compliance with the 65% long-term contracting requirement through 2027. As a result, references to MCE in the following are in error and should be stricken: Footnote 33, Table II, and Ordering Paragraph 23.

MCE Has Considered Disadvantaged Communities, Equity and Economic Development

- MCE has explicitly considered "[disadvantaged communities (DACs)], equity, and economic development in their least-cost best-fit evaluations, consistent with Pub. Util. Code § 399.13(a)(8) and the 2020 ACR." As a result, reference to MCE in Ordering Paragraph 29 is in error and should be stricken.

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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.	Rulemaking 18-07-003 (Filed July 12, 2018)

COMMENTS OF
MARIN CLEAN ENERGY
ON PROPOSED DECISION

Pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure (Rules) Marin Clean Energy respectfully submits the following opening comments on the *Proposed Decision on 2020 Renewables Portfolio Standard Procurement Plans* mailed December 11, 2020 (Proposed Decision). Pursuant to Rule 14.3(a) these opening comments are timely filed. These comments supplement the comments MCE will be filing jointly with other community choice aggregators (CCAs) on broader issues of the Proposed Decision.

The below comments address the need for corrections to the Proposed Decision in order to accurately align with MCE's 2020 Renewables Portfolio Standard (RPS) Procurement Plan filed with the Commission on July 6, 2020 (MCE RPS Procurement Plan).

I. SUMMARY OF RECOMMENDATIONS

Table I of the Proposed Decision accurately notes that MCE has achieved the 65% long-term contracting requirement for the 2021-2024 compliance period.[1] Existing MCE supply commitments place MCE in compliance with the 65% long-term contracting requirement through

[1] Proposed Decision at 44.

2027.[2] As a result, references to MCE in the following are in error and should be stricken: Footnote 33, Table II, and Ordering Paragraph 23.

Section 3.3.3.7.2. of the Proposed Decision accurately reflects that MCE has explicitly considered "[disadvantaged communities (DACs)], equity, and economic development in their least-cost best-fit evaluations, consistent with Pub. Util. Code § 399.13(a)(8) and the 2020 ACR."[3] As a result, the reference to MCE in Ordering Paragraph 29 is in error and should be stricken.

II. COMMENTS ON THE PROPOSED DECISION

A. MCE Has Achieved Long-term Contracting Requirements through 2027; References to the Contrary Are in Error

Table I of the Proposed Decision accurately notes that MCE has achieved the 65% long-term contracting requirement for the 2021-2024 compliance period.[4] Existing MCE supply commitments place MCE in compliance with the 65% long-term contracting requirement through 2027. As a result, references to MCE should be stricken in Footnote 33, Table II, and Ordering Paragraph 23.

- Footnote 33, which lists MCE as among the "newer CCAs" arguing for additional time to procure resources needed to meet imminent long-term RPS requirements.[5] MCE is not a "newer CCA" nor had MCE requested additional time to demonstrate compliance with the long-term contract planning requirement for the 2021-2024 compliance period.[6]

- Table II, which states that MCE should include "Results of 2020 Open Season RFO and ongoing contract negotiations."

- Ordering Paragraph 23, which would require MCE to "provide relevant supporting information on the timeline of contracts, project deliveries and results of ongoing contract negotiations to demonstrate that they are on a path to meet their long-term contract

[2] "With regard to long-term contracting compliance, as discussed above MCE has secured long-term contract commitments sufficient to meet the noted requirements through 2027 (or 2026 in the event of substantial delivery shortfalls)." MCE RPS Procurement Plan at 21.
[3] Proposed Decision at 67-68; MCE RPS Procurement Plan at 28.
[4] Proposed Decision at 44.
[5] Proposed Decision at 46.
[6] MCE began service customers in 2010. *See* MCE RPS Procurement Plan at 2.

planning requirement for compliance period 2021-2024." MCE has already met this long-term contract planning requirement.

B. MCE Has Considered Disadvantaged Communities, Equity and Economic Development; Reference to the Contrary Is in Error

Section 3.3.3.7.2. of the Proposed Decision accurately reflects that MCE has explicitly considered "[disadvantaged communities (DACs)], equity, and economic development in their least-cost best-fit evaluations, consistent with Pub. Util. Code § 399.13(a)(8) and the 2020 ACR."[7] As a result, the reference to MCE in Ordering Paragraph 29 should be stricken.

III. CONCLUSION

MCE thanks Commissioner Rechtshaffen and Assigned Administrative Law Judges Lakhanpal and Atamturk for their consideration of these requested revisions.

Respectfully submitted,

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December 29, 2020

[7] Proposed Decision at 67-68; MCE RPS Procurement Plan at 28.

APPENDIX A

PROPOSED FINDINGS OF FACT AND CONCLUSIONS OF LAW

Ordering Paragraphs:

23. The final 2020 Renewables Portfolio Standard Procurement Plans of Silicon Valley Clean Energy Authority, Central Coast Community Energy, ~~**Marin Clean Energy,**~~ San José Clean Energy, San Diego Community Power, EDF Industrial Power Services, Peninsula Clean Energy, Lancaster Choice Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Rancho Mirage Energy Authority, San Jacinto Power, Constellation NewEnergy, Valley Clean Energy Alliance, Clean Power Alliance, Desert Community Energy, Solana Energy Alliance, Western Community Energy, Butte Choice Energy, City of Baldwin Park, City of Commerce, City of Palmdale, City of Pomona, City of Santa Barbara, Clean Energy Alliance, East Bay Community Energy, King City Community Power, 3 Phases Renewables, American PowerNet Management, Calpine Energy Solutions, Calpine PowerAmerica, Commercial Energy of California, Just Energy Solutions, Pilot Power Group, The Regents of the University of California, and Tiger Natural Gas, also identified in Table II - Retail Sellers Long-Term Procurement Assessments in Section 3.3 of this decision, shall each provide relevant supporting information on the timeline of contracts, project deliveries and results of ongoing contract negotiations to demonstrate that they are on a path to meet their long-term contract planning requirement for compliance period 2021-2024.

29. In their final 2020 Renewables Portfolio Standard Procurement Plans, Apple Valley Choice Energy, Butte Choice Energy, City of Baldwin Park, City of Commerce, City of Palmdale, City of Pomona, City of Santa Barbara, Clean Energy Alliance, Desert Community Energy, East Bay Community Energy, King City Community Power, Lancaster Choice Energy, ~~**Marin Clean Energy,**~~ Central Coast Community Energy, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Silicon Valley Clean Energy Authority, Solana Energy Alliance, Sonoma Clean Power, Western Community Energy, 3 Phases Renewables, American PowerNet Management, LP, Calpine Energy Solutions, Calpine PowerAmerica-CA, LLC, Commercial Energy of California, Constellation NewEnergy, Inc, Direct Energy Business, EDF Industrial Power Services (CA), LLC, LLC, Just Energy Solutions, Pilot Power Group, Inc., Shell Energy, The Regents of the University of California, and Tiger Natural Gas, Inc., also identified in Table VII- Bid Solicitation Protocol in Section 3.3 of this decision, shall each describe the bid solicitation protocol, bid selection process and evaluation methodology, and bid selection criteria per Public Utilities Code Section 399.13(a)(6)(C), describe how they consider and/or provide preference to projects that provide environmental and economic benefits to communities located in areas with high levels of socioeconomic and the environmental burdens per Public Utilities Code Section 399.13(a)(8), and describe how they consider a project's best-fit attributes and the contribution to grid reliability when procuring renewables per Public Utilities Code Section 399.13(a)(9).

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.	Rulemaking 18-07-003

OPENING COMMENTS OF THE JOINT CCA PARTIES ON THE PROPOSED DECISION ON 2020 RENEWABLES PORTFOLIO STANDARD PROCUREMENT PLANS

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And on behalf of Apple Valley Choice Energy, City of Baldwin Park, City of Commerce, City of Pomona, City of Santa Barbara, Clean Power Alliance of Southern California, Marin Clean Energy, Central Coast Community Energy, Pioneer Community Energy, the City of San José, Administrator of San José Clean Energy, Silicon Valley Clean Energy Authority, and Sonoma Clean Power Authority

Dated: December 31, 2020

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SUMMARY OF JOINT CCA PARTIES' RECOMMENDATIONS

1. **CCA Solicitations and Procurement:** The PD Language should be modified to clarify that the Commission does not have jurisdiction over the renewable solicitations of CCAs and to provide greater direction on what the Commission seeks regarding least-cost best-fit methodologies.

2. **Applicability of Public Utilities Code § 399.13(a)(8) to CCAs:** The PD should be modified to clarify that the requirements of Public Utilities Code § 399.13(a)(8) are appliable to the investor owned utilities and are not expressly applicable to CCAs.

3. **MMoP Methodology:** The Commission should modify the PD to accept that MMoPs of CCAs that set their MMoP based on a locally-adopted RPS target that exceeds the statutory minimum and for the which the CCA has determined that the buffer provides adequate protection against the risk of project delay or failure. These CCAs should be struck from Table VI and Ordering Paragraph 28.

4. **Error on Disadvantaged Community Reporting:** The PD should be modified to correct the discrepancy between the text of the PD and Table VII of the PD by deleting Pioneer Community Energy from Table VII and Ordering Paragraph 29.

5. **Errors in Ordering Paragraph 29:** Peninsula Clean Energy, Marin Clean Energy, Redwood Coast Energy Authority, and the City of San José, Administrator of San José Clean Energy are not included in Table VII of the PD and should therefore be deleted from the associated Ordering Paragraph 29.

6. **Incorrect Party Name:** "Monterey Bay Community Power Authority" in footnote 43 on page 60 of the PD should be changed to Central Coast Community Energy.

**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.	Rulemaking 18-07-003

**OPENING COMMENTS OF THE JOINT CCA PARTIES ON
THE PROPOSED DECISION ON 2020 RENEWABLES PORTFOLIO STANDARD
PROCUREMENT PLANS**

In accordance with Rule 14.3 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission"), the City of Lancaster, City of Pico Rivera, City of San Jacinto, City of Rancho Mirage, Apple Valley Choice Energy, City of Baldwin Park, City of Commerce, City of Pomona, City of Santa Barbara, Clean Power Alliance of Southern California, Marin Clean Energy, Central Coast Community Energy, Pioneer Community Energy, the City of San José, Administrator of San José Clean Energy, Silicon Valley Clean Energy Authority, and Sonoma Clean Power Authority ("Joint CCA Parties") respectfully submit these opening comments on the *Proposed Decision on 2020 Renewables Portfolio Standard Procurement Plans* ("PD"), issued on December 11, 2020.[1]

[1] Pursuant to Rule 1.8(d), Apple Valley Choice Energy, City of Baldwin Park, City of Commerce, City of Pomona, City of Santa Barbara, Clean Power Alliance of Southern California, Marin Clean Energy, Central Coast Community Energy, Pioneer Community Energy, the City of San José, Administrator of San José Clean Energy, Silicon Valley Clean Energy Authority, and Sonoma Clean Power Authority have authorized the undersigned counsel to sign and file these comments on their behalf.

I. OPENING COMMENTS ON THE PD

A. The PD Language Should Be Modified to Clarify the Commission's Lack of Jurisdiction Over CCA Solicitations.

The PD states that the *Assigned Commissioner and Assigned Administrative Law Judge's Ruling Identifying Issues and Schedule of Review For 2020 Renewables Portfolio Standard Procurement Plans* ("2020 ACR"), issued on May 6, 2020, required "all retail sellers to describe their bid selection process/evaluation methodology, consistent with D.04-07-029, D.11-04-030, D.12-11-016, D.14-11-042, and D.16-12-044."[2] The PD goes on to state that some community choice aggregators ("CCAs") and electric service providers ("ESPs") "contend that the bid solicitation protocol (including least-cost best-fit methodologies) requirement only applies to [investor owned utilities ("IOUs")]."[3] The PD rejects this, arguing that "[u]nder Section 399.12(j)(2), § 399.12(j)(3), and D.19-12-042, CCAs and ESPs shall participate in the [renewables portfolio standard ("RPS")] program subject to the same terms and conditions applicable to an electrical corporation."[4]

The Joint CCA Parties agree that Public Utilities Code § 399.13(a)(6)(C) requires all retail sellers, including CCAs, to include in their RPS Procurement Plan "a bid solicitation setting forth the need for eligible renewable energy resources of each deliverability characteristic, required online dates, and locational preferences, if any." However, the Commission's authority under Public Utilities Code § 399.13(a)(5)(A) to adopt "criteria for the rank ordering and selection of least-cost best-fit eligible renewable energy resources" is

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[2] PD at 66.
[3] *Id.*
[4] PD at 67.

expressly only applicable to the IOUs.[5] The distinction between the reporting requirement expressed in Public Utilities Code § 399.13(a)(6)(C) and the authority over solicitation ranking and selection found in Public Utilities Code § 399.13(a)(5)(A) is particularly important because local authority over procurement decisions is a core purpose for CCAs and is expressly protected in statute.[6] Much of the direction provided in D.04-07-029, as modified by D.11-04-030, D.12-11-016, D.14-11-042, and D.16-12-044 is specific to the IOUs and is not applicable to the Commission's review of CCA RPS Procurement Plans. In order to provide sufficient direction to CCAs that must update this section in their Final RPS Procurement Plans, the PD should be

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[5] *See* Cal. Pub. Util. Code § 399.13(a)(5): "The commission shall adopt, by rulemaking, all of the following:

> (A) A process that provides criteria for the rank ordering and selection of least-cost and best-fit eligible renewable energy resources to comply with the California Renewables Portfolio Standard Program obligations on a total cost and best-fit basis. This process shall take into account all of the following:
> (i) Estimates of indirect costs associated with needed transmission investments.
> (ii) The cost impact of procuring the eligible renewable energy resources on the ***electrical corporation's*** electricity portfolio.
> (iii) The viability of the project to construct and reliably operate the eligible renewable energy resource, including the developer's experience, the feasibility of the technology used to generate electricity, and the risk that the facility will not be built, or that construction will be delayed, with the result that electricity will not be supplied as required by the contract.
> (iv) Workforce recruitment, training, and retention efforts, including the employment growth associated with the construction and operation of eligible renewable energy resources and goals for recruitment and training of women, minorities, and disabled veterans.
> (v)(I) Estimates of ***electrical corporation*** expenses resulting from integrating and operating eligible renewable energy resources, including, but not limited to, any additional wholesale energy and capacity costs associated with integrating each eligible renewable resource.
> (II) No later than December 31, 2015, the commission shall approve a methodology for determining the integration costs described in subclause (I).
> (vi) Consideration of any statewide greenhouse gas emissions limit established pursuant to the California Global Warming Solutions Act of 2006 (Division 25.5 (commencing with Section 38500) of the Health and Safety Code).
> (vii) Consideration of capacity and system reliability of the eligible renewable energy resource to ensure grid reliability." (emphasis added).

[6] *See, e.g.,* Cal. Pub. Util. Code § 366.2(a)(5) ("[CCAs] shall be solely responsible for all generation procurement activities on behalf of the [CCA's] customers, except where other generation procurement arrangements are expressly authorized by statute."). *See also* Cal. Pub. Util. Code § 380(h)(5) (requiring that the Commission "ensur[e] that community choice aggregators can determine the generation resources used to serve their customers.").

modified to clarify what elements of a CCA's bid solicitation information, reported pursuant to Public Utilities Code § 399.13(a)(6)(C), must be consistent with D.04-07-029, D.11-04-030, D.12-11-016, D.14-11-042, and D.16-12-044. Further, in order to ensure that these reporting requirements are consistent with the limits on the authority of the Commission over the solicitation and procurement activities of CCAs, any such clarification should also provide the specific statutory authority that is expressly applicable to CCAs or retail sellers.

B. The PD Incorrectly Asserts That Public Utilities Code § 399.13(a)(8) is Applicable to CCAs.

Each of the Joint CCA Parties is committed to advancing California's goals of stimulating economic growth in disadvantaged communities while also reducing localized air pollution that disproportionately affects these communities. Consistent with this commitment, each of the Joint CCA Parties included in its RPS Procurement Plans the relevant information on the policies and direction from its governing board on incorporating preferences for renewable generation located in disadvantaged communities or communities with high levels of socioeconomic and environmental burdens.

Further, the Joint CCA Parties do not object to the direction in the 2020 ACR for CCAs to ***report*** on any such direction from their governing boards or to otherwise describe how each CCA gives a preference to RPS projects that provide benefits to disadvantaged communities. However, the language of Public Utilities Code § 399.13(a)(8) is expressly only applicable to the IOUs, and deals exclusively with the actual preferences that the IOUs must provide in their solicitations and procurement. This code section does not provide direction to retail sellers, generally, and does not specify any requirements for RPS Procurement Plan reporting. Specifically, Public Utilities Code § 399.13(a)(8) provides:

> (A) In soliciting and procuring eligible renewable energy resources for California-based projects, ***each electrical corporation*** shall give preference to renewable energy projects that provide environmental and economic benefits to communities afflicted with poverty or high unemployment, or that suffer from high emission levels of toxic air contaminants, criteria air pollutants, and greenhouse gases.
>
> (B) Subparagraph (A) applies to all procurement of eligible renewable energy resources for California-based projects, whether the procurement occurs through all-source requests for offers, eligible renewable resources only requests for offers, or other procurement mechanisms. This subparagraph is declaratory of existing law.[7]

Despite this clear language, the PD describes the requirements of Public Utilities Code § 399.13(a)(8) as applicable to all retail sellers, not just the IOUs: "According to Pub. Util. Code § 399.13(a)(8) and the 2020 ACR, ***retail sellers*** should describe how their solicitations give preference to RPS projects that provide environmental and economic benefits to communities with high levels of socioeconomic and environmental burdens."[8] This characterization is incorrect as Public Utilities Code § 399.13(a)(8) does not provide any express direction to CCAs. The Commission should revise the PD accordingly, and make the changes to the conclusions of law and ordering paragraphs as provided in Appendix A.

C. <u>The Commission Should Not Require CCAs with RPS Targets that Exceed the Statutory Minimum to Utilize a Risk-Informed MMoP Methodology.</u>

The 2020 ACR directed retail sellers to include in their RPS Procurement Plans a minimum margin of over-procurement ("MMoP") that is set at a level sufficiently above the minimum RPS procurement requirements in order to mitigate the risk that renewable projects under contract could be delayed or terminated.[9] This direction regarding the MMoP is nearly identical to the direction provided in the 2019 ACR.[10] In both 2019 and 2020 RPS Plans, many

[7] Cal. Pub. Util. Code § 399.13(a)(8)(A), (B) (emphasis added).
[8] PD at 67 (emphasis added).
[9] 2020 ACR at 22.
[10] *See Assigned Commissioner and Assigned Administrative Law Judge's Ruling Identifying Issues and Schedule of Review For 2019 Renewables Portfolio Standard Procurement Plans* ("2019 ACR"), issued April 19, 2019 at 15-16.

CCAs have reported that their governing boards have adopted local RPS targets that significantly exceed the minimum statutory RPS procurement requirements. This buffer generally far exceeds any margin that would reasonably be necessary to mitigate the risk of project delay or failure. Thus, many of these CCAs report their MMoP as the percentage by which their locally-adopted targets exceed the statutory minimum.

In the *Decision on 2019 Renewables Portfolio Standard Procurement Plans* ("D.19-12-042"), issued on December 30, 2019, the Commission provided a table that identified those CCAs that set a MMoP with an adequate rationale.[11] All of the CCAs that set their MMoP based on locally-adopted targets that exceed the statutory minimums were determined to be compliant with this requirement without any indication that this practice was in any way deficient. Further, the 2020 ACR gave no indication that these CCAs should alter this practice for their 2020 RPS Procurement Plans.

However, the PD now finds that these CCA RPS Procurement plans are inadequate because they do not provide the methodology used to determine the MMoP and that these CCAs must revise their RPS Plans to quantify their MMoP based on a risk-informed methodology.[12] The Joint CCA Parties urge the Commission to reconsider this determination and return to the approach taken in D.19-12-042. Where a prior Commission Decision expressly approves a certain practice, as is the case here, the Commission should provide direction to change this practice in the following year's ACR rather than in the ultimate decision on the RPS Procurement Plans. A retail seller's RPS Plan should not be found to be inadequate without being provided sufficient notice and opportunity to correct any such deficiency.

[11] D.19-12-042 at 47-50.
[12] PD at 64-65.

Further, it is unclear why the PD now apparently finds this approach to be inadequate. These CCAs did not only set their MMoPs based on locally-adopted targets, but they also made the determination that their increased procurement requirement was sufficient to exceed any buffer necessary to mitigate the risk of project delay or failure. For many of these CCAs, this determination is based on an existing track record of securing RPS procurement. A risk-based methodology, particularly based on complex models, can be both costly to develop and take substantial staff resources. Where a CCA has a locally-adopted RPS target that far exceeds the statutory minimum and where the historical track record of the CCA demonstrates that this margin is sufficient to mitigate the identified risks, the Commission should not require that the CCA develop a costly and burdensome methodology. Such a requirement can detract from other more valuable efforts that support the RPS program.

The Joint CCA Parties urge the Commission to either take the same approach as D.19-12-042 or alternatively, expressly clarify that more limited demonstration requirements are applicable for CCAs with locally-adopted RPS targets that exceed the statutory minimum. These CCAs should be struck from Table VI and conforming changes should be made to the findings of fact, conclusions of law, and ordering paragraphs as specified in Appendix A.

D. Correct Various Errors.

In addition to the issues identified above, the Joint CCA Parties request that the Commission correct the following errors in the PD.

1. Correct Error Regarding Pioneer Community Energy and Reporting on Disadvantaged Communities.

On page 67, the PD correctly notes that several CCAs, including Pioneer Community Energy "explicitly consider DACs, equity, and economic development in their least-cost best-fit evaluations, consistent with Pub. Util. Code § 399.13(a)(8) and the 2020 ACR." However, Table

VII on pages 70 and 71 of the PD identifies Pioneer Community Energy as needing to address Public Utilities Code § 399.13(a)(8) in its Final RPS Procurement Plan.[13] The inclusion of Pioneer Community Energy in Table VII is clearly in error and should be deleted. Consistent with this deletion, Pioneer Community Energy should also be struck from Ordering Paragraph 29, as reflected in Appendix A.

2. Correct Errors in Ordering Paragraph 29

Section 3.3.3.7 of the PD provides the proposed determinations on reporting requirements relating to Public Utilities Code Section 399.13(a)(6)(C), (a)(8), and (a)(9). Table VII of the PD provides the direction to CCAs and ESPs regarding what corrections need to be made to their final RPS Procurement Plans based on the proposed findings in the PD.[14] Ordering Paragraph 29 then lists the CCAs and ESPs that must make these corrections in their final plans. However, there are several inconsistencies between the direction provided in Table VII and Ordering Paragraph 29. While Peninsula Clean Energy,[15] Marin Clean Energy, Redwood Coast Energy Authority, and the City of San José, Administrator of San José Clean Energy are all absent from Table VII, all of these CCAs are mistakenly included in Ordering Paragraph 29. As reflected in Appendix A, these CCAs should be struck from Ordering Paragraph 29.

3. Correct Name for Central Coast Community Energy

On September 4, 2020, the Monterey Bay Community Power Authority filed a notice in this Rulemaking that its name had been changed to Central Coast Community Energy. However, the PD still uses the name Monterey Bay Community Power Authority in footnote 43 on page 60. The PD should correct this error.

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[13] PD at 70.
[14] PD at 70-71.
[15] Further, Peninsula Clean Energy is listed as a “best practice” RPS Procurement Plan for these requirements. PD at 69, footnote 51.

II. CONCLUSION

The Joint CCA Parties appreciate the opportunity to provide these opening comments on the PD.

December 31, 2020,

Respectfully submitted,

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Appendix A

Joint CCA Parties' Proposed Changes to
Findings of Fact, Conclusions of Law, and Ordering Paragraphs

Proposed text deletions are in red and strikethrough (~~abcd~~)
Proposed text additions are in blue and double underlined (abcd)

I. CHANGES TO FINDINGS OF FACT

~~32. Some CCAs and ESPs rely on existing or over-procured generation to mitigate the risk of not receiving electricity deliveries as required by their contract.~~

34. It is not reasonable for CCAs and ESPs to ~~use over-procured RPS resources or banked RECs as a substitute to MMoP or to~~ set an arbitrary MMoP without proper supporting analyses.

II. CHANGES TO CONCLUSIONS OF LAW

32. CCAs and ESPs identified in Table VII- Bid Solicitation Protocol, should describe in their final 2020 RPS Plans their bid solicitation protocol, bid selection process and evaluation methodology, and bid selection criteria per Pub. Util. Code § 399.13(a)(6)(C); describe how they consider and/or provide preference to projects that provide environmental and economic benefits to communities located in areas with high levels of socioeconomic and environmental burdens ~~per Pub. Util. Code § 399.13(a)(8)~~; and describe how they consider a project's best-fit attributes and the contribution to grid reliability when procuring renewables as required by Pub. Util. Code § 399.13(a)(9).

III. CHANGES TO ORDERING PARAGRAPHS

28. Apple Valley Choice Energy, Butte Choice Energy, City of Baldwin Park, City of Commerce, City of Palmdale, City of Pomona, City of Santa Barbara, Clean Energy Alliance, ~~Clean Power Alliance,~~ Desert Community Energy, East Bay Community Energy, King City Community Power, Lancaster Choice Energy, ~~Marin Clean Energy,~~ Central Coast Community Energy, ~~Peninsula Clean Energy,~~ Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, ~~San José Clean Energy, Silicon Valley Clean Energy Authority,~~ Solana Energy Alliance, ~~Sonoma Clean Power,~~ Valley Clean Energy Alliance, Western Community Energy, 3 Phases Renewables, American PowerNet Management, LP, Calpine Energy Solutions, Calpine PowerAmerica-CA, LLC, Commercial Energy of California, Constellation NewEnergy, Inc, Direct Energy Business, EDF Industrial Power Services (CA), LLC, LLC, Just Energy Solutions, Pilot Power Group, Inc., Shell Energy, The Regents of the University of California, and Tiger Natural Gas, Inc., also identified in Table VI – Minimum Margin of Procurement (MMoP) Findings and Corrective Action Needed in Section 3.3 of this decision, shall each update their final 2020 Renewables Portfolio Standard Procurement Plan with a MMoP, an MMoP methodology to mitigate risk and supporting scenarios, and update the renewable net short table.

29. In their final 2020 Renewables Portfolio Standard Procurement Plans, Apple Valley Choice Energy, Butte Choice Energy, City of Baldwin Park, City of Commerce, City of Palmdale, City of Pomona, City of Santa Barbara, Clean Energy Alliance, Desert Community Energy, East Bay Community Energy, King City Community Power, Lancaster Choice Energy, ~~Marin Clean Energy,~~ Central Coast Community Energy, ~~Peninsula Clean Energy,~~ Pico Rivera Innovative Municipal Energy, ~~Pioneer Community Energy,~~ Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, ~~San José Clean Energy,~~ Silicon Valley Clean Energy Authority, Solana Energy Alliance, Sonoma Clean Power, Western Community Energy, 3 Phases Renewables, American PowerNet Management, LP, Calpine Energy Solutions, Calpine PowerAmerica-CA, LLC, Commercial Energy of California Constellation NewEnergy, Inc, Direct Energy Business, EDF Industrial Power Services (CA), LLC, LLC, Just Energy Solutions, Pilot Power Group, Inc., Shell Energy, The Regents of the University of California, and Tiger Natural Gas, Inc., also identified in Table VII- Bid Solicitation Protocol in Section 3.3 of this decision, shall each describe the bid solicitation protocol, bid selection process and evaluation methodology, and bid selection criteria per Public Utilities Code Section 399.13(a)(6)(C), describe how they consider and/or provide preference to projects that provide environmental and economic benefits to communities located in areas with high levels of socioeconomic and the environmental burdens ~~per Public Utilities Code Section 399.13(a)(8)~~, and describe how they consider a project's best-fit attributes and the contribution to grid reliability when procuring renewables per Public Utilities Code Section 399.13(a)(9).