JANUARY FILINGS

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January 4, 2021

Via E-Mail (EDTariffUnit@cpuc.ca.gov)

Energy Division, Tariff Unit
California Public Utilities Commission
505 Van Ness Avenue, 4th Floor
San Francisco, California 94102

Subject: **Protest of Peninsula Clean Energy Authority, Sonoma Clean Power Authority, Redwood Coast Energy Authority, Pioneer Community Energy, Central Coast Community Energy, and Marin Clean Energy to PG&E Advice Letter 6017-E**

Dear Energy Division Tariff Unit:

Peninsula Clean Energy Authority, Sonoma Clean Power Authority, Redwood Coast Energy Authority, Pioneer Community Energy, Central Coast Community Energy, and Marin Clean Energy ("Joint CCAs") hereby protest Pacific Gas and Electric Company's ("PG&E") Advice Letter 6017-E (the "Advice Letter"), with sets forth PG&E's Remote Grid Proposal.

INTRODUCTION

PG&E's Remote Grid proposal, properly refined, is a potentially promising solution to provide some customers in remote locations with reliable electric service without jeopardizing public safety. As described in the Advice Letter ("AL"), PG&E's Remote Grids would be microgrids deployed to serve small numbers of customers with small load (predominantly under 20 kW) at the end of long radial transmission and distribution ("T&D") lines in remote locations. These microgrids would be *permanently islanded* and powered by an on-site stand-alone power system ("SPS"), and the existing distribution lines serving these customers would be removed.[1]

The Joint CCAs view Remote Grids as a potentially promising solution to a number of wildfire-safety and outage-related problems. Where small numbers of customers in remote locations are served by a long distribution line, particularly one that traverses rough or heavily vegetated terrain, Remote Grids may be an attractive and cost-saving alternative to other safety investments such as undergrounding or line hardening.

However, as with so many complex utility proposals, the devil is in the details. As set forth below, PG&E's proposal raises several concerns that form the basis for this Protest. In addition, the Joint CCAs note a number of areas where PG&E's AL requires more detail.

1 AL at 1-3.

PROTEST

A. PG&E's Proposal Is Not Appropriate For An Advice Letter And Should Be Resubmitted As A Limited Pilot Program

Section 5.2 of General Order 96-B specifically prohibits the use of the Advice Letter process to seek "relief that the Commission can grant only… by decision rendered in a formal proceeding," or to seek "Commission approval of a proposed action that the utility has not been authorized, by, statute, by this General Order, or by other Commission order, to seek by advice letter."

In the AL, PG&E requests Commission approval of an ambitious, open-ended *new program* that would have significant customer, rate, and safety impacts. While the Remote Grid program would start with 3 initial projects, it does not appear that there would be any limit on the Remote Grids program's duration or the number of Remote Grids that would be installed. While PG&E notes that it anticipates to eventually identify several hundred Remote Grid sites, it is unclear if this would be the maximum number of projects to be identified under the initiative or if additional projects could be identified in future phases of the program.

Critically, the Remote Grids program has not been formally considered or approved by the Commission, and it does not appear that PG&E intends to seek direct Commission approval of the Remote Grids program through an application. While PG&E frames the AL as a tariff modification request, it appears that the AL is in fact an attempt to use the advice letter process to implement a major program without full Commission review.

While elements of PG&E's Remote Grids proposal were included in PG&E's 2020 Wildfire Mitigation Plan ("WMP"),[2] this inclusion in PG&E's WMP does not constitute Commission approval of the Remote Grids proposal, nor is it a valid substitute for a full application to consider PG&E's proposal. PG&E's 2020 WMP provides very little detail of PG&E's proposal, far less than is required for meaningful review and regulatory approval of the Remote Grids program. Further, the WMP does not propose appropriate regulatory approval for the initial phase of the program or future developments, and only commits to "deliver recommendations for scale up and/or further development for consideration in 2021 and beyond."[3]

The CCAs support efforts to reduce potential wildfire ignition points but caution that measured steps should be taken to prevent unintended consequences that could negatively impact communities and customers. In order to ensure that the benefits from Remote Microgrids are realized while also ensuring appropriate Commission review of PG&E's Remote Microgrids program as a whole, the Joint CCAs propose the following:

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2 *See*, PG&E WMP at 5-19. Available at: https://www.pge.com/pge_global/common/pdfs/safety/emergency-preparedness/natural-disaster/wildfires/wildfire-mitigation-plan/2020-Wildfire-Safety-Plan.pdf

3 *Id*.

1. The Commission should instruct PG&E to re-file an amended AL that includes a) the tariff changes needed to implement the remote grids proposal; and b) a request for Commission approval of PG&E's first "tranche" of microgrids, consisting of those "initial Remote Grid projects" PG&E specifies in the AL.[4]

2. The Commission should allow PG&E to include in its first tranche of Remote Microgrids the three Remote Microgrid projects specifically identified in the AL, as well as any other Remote Microgrid projects that PG&E intends to complete by the end of 2022. However, the Commission should require that PG&E specifically identify and describe all additional projects to be included in the first tranche in the Advice Letter.

3. The Commission should instruct PG&E to file an Application, as soon as practical, seeking approval of the overall Remote Microgrids program. Given the safety issues involved, the Joint CCAs believe that expedited consideration of this Application would be appropriate.

4. All costs associated with the first tranche of the Remote Microgrids program would be recorded to a separate sub-account of PG&E's Microgrids memorandum account. The reasonableness of these costs as well as appropriate cost allocation and recovery would be addressed in PG&E's Remote Microgrids application proceeding.

5. Costs associated with future Remote Microgrids tranches would be addressed in PG&E's application proceeding.

This approach ensures that those Remote Microgrid projects that can be initiated in the near future are not delayed, while still ensuring that the Remote Microgrid program as a whole is given the appropriate level of Commission review. It would also provide appropriate cost recovery mechanisms for the projects, and would ensure that all projects included in the first tranche of Remote Microgrids are adequately identified and described, and are given some Commission review before being initiated.

Once implemented, the review of a full Remote Grid program should include consideration of many of the issues now pending in the Microgrid Proceeding, including the impact of IOU participation on commercialization. In particular, the Commission should assess the risk that IOU development of a fully implemented "Remote Grid" program would have anti-competitive impacts on third-party microgrid providers and non-IOU LSE service. The Commission must determine whether it is appropriate for the IOUs to own and operate microgrids beyond a case-by-case basis when such facilities are owned and operated within a competitive market with non-utility participants. The question of whether PG&E could inappropriately expand its distribution service monopoly into competitive DER markets, exercise market power or inhibit third-party competition entry or pose other barriers to entry for non-IOU market participants must be considered in the full, formal proceeding.

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[4] AL at 6.

B. PG&E Must Be Required To More Specifically Define Remote Grids

While the AL provides a generally usable description of many of the *attributes* of Remote Grids, it does not propose clear definitional *boundaries* that would determine what does or doesn't qualify as a Remote Grid. Critically, the AL does not include maximum thresholds for the load served by a Remote Microgrid, the maximum SPS size connected to a Remote Grid, or the number of customers to be served by a Remote Grid. Instead, the AL provides only vaguely reassuring statements, claiming that:

- The "predominant size" of each customer load to be served by each Remote Grid is expected to be 20 kW,[5]
- Each Remote Grid will serve "few" or a "small number" of "remote" customers.
- PG&E expects to eventually have a Remote Grid portfolio with "hundreds" of individual SPS "serving customer meters ranging from upper hundreds to low thousands in total."[6]

The vagueness of these statements and the lack of firm upper boundaries on the size of Remote Grids leave open the possibility of a potentially significant expansion of the program beyond the current program intent implied in the AL. In order to remedy this issue, the Joint CCAs request that PG&E be required to include the following information in its Application for the full Remote Grid Program:

- Estimated average system size of SPS ("target" load to be served by a normal Remote Grids project).
- Maximum system size for a Remote Grid's SPS (in kilowatts).
- Maximum number of customers to be served under the overall Remote Grids program.
- Maximum number of customers to be served by a single Remote Grid.
- Maximum number of projects under the Remote Grid program.
- A complete list of all potential sites identified to date (including those in CCA service area of course).
- Actual or anticipated resource mix for each project.

Furthermore, we recommend that PG&E include additional details about project/ customer selection criteria in the AL (e.g., criteria for selection, location of customers/ remote grids, types of customers, expected load per customer, prioritization of High Fire Threat District segments, etc.). The CCAs encourage PG&E to expand upon the criteria and the associated prioritization of those criteria to provide a better understanding of how PG&E will approach locations for evaluation.

[5] AL at 5.
[6] *Id*.

Finally, the CCAs further ask that PG&E be required to provide specific information regarding each of the proposed Remote Grid projects contemplated under the first tranche of the program in the amended AL including:

- The project's location.
- The number and type of customers to be served by the project.
- System size of SPS.
- The resource mix, including the renewable/ non-renewable mix, of the SPS.

C. PG&E Erroneously Characterizes Remote Grids As Distribution Assets

In the AL, PG&E claims that it "views Remote Grid assets as distribution assets." This assertion appears to apply to *all* Remote Grid elements, including the SPS generation assets that would generate power for the Remote Grid customers.

This assertion is plainly incorrect. The microgrid elements of Remote Grids will serve a distribution function, while the SPS generation elements will serve a generation function because the proposed Remote Grid would be providing for all electricity needs, not just back-up power. To distract from this plain reality PG&E offers a red herring, asserting that the Remote Grids are distribution assets because they "will substitute for traditional distribution work."[7] While it is true that Remote Grids as a whole will replace existing distribution assets serving these customers, presumably allowing PG&E to avoid distribution upgrade costs while theoretically reducing wildfire ignition risk, the Remote Grids will also replace the existing generation serving these customers. Thus, Remote Grids include both distribution and generation assets from both a plain factual perspective and from a cost causation / cost avoidance perspective.

This erroneous characterization is problematic for two reasons. First, mischaracterizing the generation elements of Remote Grids (the SPS) could lead to unjust and unreasonable allocation of generation costs to distribution customers, including CCA customers. Second, the CCAs are concerned that PG&E may use the erroneous claim that SPS are distribution rather than generation assets as an end-run around CCAs statutory right to provide CCA customers with generation service. To remedy these issues, the Joint CCAs ask that PG&E be instructed to file an amended AL that is corrected to clearly identify SPS as generation assets.

D. PG&E's Proposal Must Be Modified To Better Address Remote Grids In CCA Service Areas

PG&E's Remote Grid proposal would have direct impacts on CCAs and CCA customers. PG&E states that based on its preliminary screening, "just under half of the few hundreds of line segment opportunities may be within [CCA] service areas."[8] PG&E further states that Remote Grids would be most effective if they serve "some dozens to low hundreds of customers in several CCA areas."[9] It is unclear whether this means that PG&E anticipates that Remote Grids

[7] AL at 9.
[8] AL at 10.
[9] *Id*.

may serve a total of dozens to low hundreds in each CCA's service area or in the service areas of all currently existing CCAs combined. In either case, Remote Grids may end up serving significant number of CCA customers.

The AL states that "there are several Remote Grid opportunities in CCA areas which PG&E may wish to pursue in collaboration with the relevant CCA." PG&E further states that "Before undertaking any Remote Grid development work in an area served by both PG&E and a CCA, PG&E will collaborate with the appropriate CCA to try to identify a practical and mutually-agreeable way to implement the Remote Grid in that area for the benefit of all distribution customers."[10] While these statements are encouraging, the Joint CCAs note that they fall short of specific binding commitments by PG&E to recognize and respect CCAs' statutory right to procure generation resources on their customers' behalf.[11]

Based on conversations with PG&E, it is the CCAs' understanding that none of the initial projects planned under the first tranche of Remote Grids are located in CCA service areas. However, if this changes and any of the first tranche Remote Grids to be developed are indeed located in a CCA service area, the Commission should require that PG&E secure explicit support for the project from the relevant CCA and clearly indicate this support in the amended AL. In addition, the amended AL should include a formal commitment by PG&E to allow any CCA that would have a first tranche Remote Grid in its service area to, at its discretion, direct the type of SPS to be procured for that Remote Grid or self-provide the Remote Grid's SPS.

The Commission should further direct PG&E to provide, in its Remote Grids Application, a detailed formal proposal for ensuring that CCAs are fully integrated into PG&E's processes for planning, siting, and developing Remote Grids *prior to beginning the planning process*. Recognizing that many CCAs have Board-adopted policies governing preferences for generation assets – often similar to the State's loading order – CCAs must be able to approve which types of SPS generation assets are used to serve their customers.

Further, the Commission should require that PG&E identify any long-range planning regarding potential project locations in CCA service areas in the Application for the full Remote Grid program, including, but not limited to, a list of areas and customers that are being considered for Remote Grids in CCA service areas and individual project assumptions. PG&E should further be required to provide each CCA with full documentation of the planning that relates to its service area. That information would be helpful to better understand the proposal and to work with local officials to identify the benefits of such projects.

PG&E should further be required to include in the Application an explanation of how it will comply with the CCA Code of Conduct in implementing the Remote Grids program in CCA territory. The CCA Code of Conduct imposes strict requirements on IOU marketing against CCAs, including encouraging CCA customers to opt-out of CCA service. Rule 18 of the CCA Code of Conduct specifically states that IOUs "shall not condition or tie the provision of any product, service, or rate agreement to a customers' participation or non-participation in a CCA

10 *Id*.
11 Pub. Util. Code Section 366.2(a)(5).

program."[12] The Remote Grids proposal raises a number of potential compliance issues, and PG&E should be required to explain how it intends to ensure that Remote Grids customers will not be encouraged or required to opt out of CCA service in order to participate in the program.

E. PG&E Should More Clearly Address Cost Issues

As set forth in the AL, a Remote Grid must serve a small cluster of customers whose load is disproportionate to the cost of the extensive network of distribution lines needed to provide electric service. PG&E asserts that Remote Grids are likely to be cost-effective alternatives to costly distribution line safety upgrades.

While this assertion seems intuitively reasonable, the Joint CCAs are concerned that the cost component of the proposal needs some enhancement and detail. The Commission should require that PG&E's amended AL and Application include specific information about project costs in comparison to these savings, how PG&E plans to balance and reconcile the initial investment with the savings from the reduced transmission and distribution costs, and how generation will be factored into the equation, especially as it relates to rates and cost of service. The CCAs encourage PG&E to put forth an example to examine in detail as much known cost as is available for the project in comparison to savings data for all associated costs such as maintenance, repair, vegetation management for the affected transmission/distribution lines and associated shareholder liability of causing additional fires. PG&E proposes to treat the SPS as distribution assets, but at least some portion of the SPS are generation and should be captured and billed as generation costs. The AL would benefit from a deeper discussion of the details on cost savings and system-benefit valuation that would be credited against the design, installation, operation, and maintenance of the Remote Grid. However, the Joint CCAs believe that the question of cost allocation and cost recovery for the Remote Grids program, including the allocation and recovery of Tranche 1 Remote Grid costs recorded in the memorandum account, should be addressed in the dedicated Remote Grids application proceeding.

All costs associated with the first tranche of Remote Grids should be recorded to a Memorandum Account and reviewed in PG&E's Remote Grids application proceeding. The Commission should reject PG&E's request to record some Remote Grids program costs to GRC-funded work categories.[13] Allowing immediate cost recovery is not appropriate, as the Remote Grids program has not been subject to a Commission reasonableness review.

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12 D.12-12-036 Appendix A (CCA Code of Conduct) at A1-8

13 AL at 10.

CONCLUSION

For the reasons set forth above, the Joint CCAs request that Commission reject the Advice Letter and instruct PG&E to re-file an amended Advice Letter that addresses the concerns discussed above.

Dated: January 4, 2021

Respectfully submitted,

/s/David Peffer

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Service List, R.19-09-009

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)

REPLY COMMENTS OF THE JOINT CCAS ON TRACK 2 PROPOSED DECISION

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**REPLY COMMENTS OF THE JOINT CCAS
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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 reply 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").

I. REPLY TO GENERAL COMMENTS ON TRACK 2 ISSUES

A. The Commission Should Address Campus Microgrids And Microutilities In Track 3

The Joint CCAs note the compelling legal analysis presented by Google and Sunrun suggesting that, based on prior court precedent, Section 218 "public utility" status may not apply to "campus" microgrids, even if they serve multiple tenants.[2] While the Joint CCAs do not take a position on this legal analysis at this point, they believe that it is appropriate for this question to be explicitly included within the scope of Track 3 of this Rulemaking, and that any changes to

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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"); California Choice Energy Authority ("CalChoice"); Central Coast Community Energy ("3CE"); San Diego Community Power ("SDCP"); and Marin Clean Energy ("MCE").

[2] Google Opening Comments at 4-9; Sunrun Opening Comments at 4-8.

investor-owned utility tariffs approved in Track 2 should not impose barriers to the implementation of the campus microgrid model discussed by Google and Sunrun. The Joint CCAs similarly believe that Sunrun's arguments regarding the potential use of the Commission's authority to exempt microutilities from certain regulatory requirements under Sections 2780 and 2780.1 in the microgrids context[3] should included in the scope of Track 3 and fully addressed in that track.

B. The Commission Should Require The IOUs To Fully Coordinate On Permanent Generation Solutions

The Joint CCAs strongly agree with the Sierra Club's proposed modification to page A-8 of the interim approach, which would require that IOUs include CCAs and other local government entities in both the design and development of permanent generation resources to replace temporary generation, rather than just the development of these resources.[4] As detailed in the Joint CCAs' opening comments, CCAs must be included in all steps of the planning, design, implementation, and operation of generation resources that serve CCA customers. In addition, CCAs should be able to self-provide generation for these projects, and IOU projects should conform to the resource preferences and policies of the jurisdictional CCA.

II. REPLY TO COMMENTS ON THE PD'S ADOPTION OF STAFF PROPOSALS

A. Reply to Comments on Proposal 2: Critical Facility Microgrids on Adjacent Parcels

The Joint CCAs strongly agree with the Microgrids Resource Coalition ("<u>MRC</u>") that the proposed Rule 18/19 exeption should be expanded to allow CFM's to operate during normal grid conditions.[5] As MRC correctly notes, microgrids are not backup power, and no rules should be

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3 Sunrun Opening Comments at 8.
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approved that relegate microgrids to such a limited use case. The Joint CCAs have been working with many customers and critical facilities that are considering implementing microgrids in their communities and it has been shown that customers will not invest in microgrids to simply serve as backup power. The economics of such a use case simply don't work out. Hence, by limiting CFMs to only operate during outage conditions, the Commission imposes a significant barrier to the commercialization of microgrids.

B. Reply to Comments on Proposal 4: Microgrid Incentive Program

The Joint CCAs support PG&E's proposals for the Microgrid Incentive Program. Specifically, the Joint CCAs agree that the COD for qualifying programs should be moved to 24 months after approval of Implementation advice letter. The Joint CCAs further agree that the Commission should clarify that Microgrid Incentive Program eligibility is limited to front-of-meter resources in order to avoid duplicative coverage with the Self-Generation Incentive Program. Both of these recommendations are reasonable, and will make the incentive program more effective and easier to implement.

III. CONCLUSION

The Joint CCAs thank the Commission for its consideration of these Reply Comments on the Track 2 PD.

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Respectfully submitted,

/s/David Peffer

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Rulemaking	20-11-003
Exhibit	____
Date	January 11, 2021
Witness	Various
ALJ	Brian Stevens

DIRECT TESTIMONY OF

NICHOLAS J. PAPPAS
MICHAEL HYAMS
MATTHEW LANGER
MAHAYLA SLACKERELLI AND
SAMANTHA WEAVER

ON BEHALF OF

CALIORNIA COMMUNITY CHOICE ASSOCIATION

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

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Table of Contents

CHAPTER 1. WITNESS – NICHOLAS J. PAPPAS

I. INTRODUCTION

In response to the Commission's recent *Order Instituting Rulemaking Emergency Reliability,*[1] many diverse stakeholders representing a wide range of interests and businesses submitted thoughtful and thought-provoking comments. The California Community Choice Association (CalCCA) joins with these stakeholders and the California Public Utilities Commission (Commission) to work together to address the risk of reliability events occurring on the immediate planning horizon, with a particular focus on Summer 2021.

Chapter 1 of this Testimony has been prepared on behalf of CalCCA by or under the supervision of Nicholas J. Pappas, Director of Strategic Initiatives and Outreach. Mr. Pappas' qualifications are set forth in Attachment A. This Chapter addresses energy supply concerns in Summer 2021, and CalCCA's support for consideration of the various supply- and demand-side policy options, such as incremental supply-side procurement, expansion of demand response procurement, critical peak pricing, and other demand-side solutions on an emergency basis. CalCCA believes that these solutions should be considered on their merits – the likelihood that they will succeed in reducing reliability risk, the potential for their successful execution, their expected cost to ratepayers, the fair allocation of those costs, and other factors. Further, the solutions must be appropriately tailored in magnitude to the problem at hand: the Commission should ensure the cumulative expected impact from Commission-authorized supply and demand solutions should be roughly equivalent to the net need for Summer 2021 for customers served by Commission-jurisdictional Load Serving Entities (LSEs).

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[1] R.20-11-003, November 19, 2020.

To support this "right-sizing" of Commission-authorized procurement, this testimony addresses the likely quantity of need for Summer 2021, focusing on interpretation of the analyses submitted into the record by the California Independent System Operator Corporation (CAISO)[2] and Southern California Edison (SCE).[3] The CAISO analysis replicates and updates the 2019 "stack analysis" performed by the Commission's Energy Division (ED).[4] SCE presents a stochastic Loss of Load Expectation (LOLE) study adapted from its 2019-2020 Integrated Resource Plan.[5] CalCCA offers observations and interpretations from these analyses based on their different inputs and methodological approaches.

Following these analyses and comments from other stakeholders, the Commission issued *Assigned Commissioner's Ruling Directing the State's Three Large Electric Investor - Owned Utilities to Seek Contracts for Additional Power Capacity to Be Available by The Summer of 2021 or 2022* on December 28, 2020 (December Ruling) and, subsequently, issued the proposed *Decision Directing Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company to Seek Contracts for Additional Power Capacity for Summer 2021 Reliability* on January 8, 2021 (January PD). Under more forgiving conditions, a rigorous LOLE analysis would be the prudent approach. CalCCA acknowledges, however, that the compressed timeline leading into Summer 2021 virtually forecloses any significant additional analysis at this time. Regardless, the Commission must determine the scale of the reliability

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[2] Comments of the California Independent System Operator Corporation on Order Instituting Rulemaking Emergency Reliability, November 30, 2020.

[3] Southern California Edison Company's (U-338) Comments on 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, November 30, 2020.

[4] *Assigned Commissioner and Administrative Law Judge's Ruling Initiating Procurement Track and Seeking Comment on Potential Reliability Issues*, R.16-02-007, June 20, 2019, at 12.

[5] Integrated Resource Plan of Southern California Edison Company (U 338-E), R.20-05-003, September 1, 2020.

need, and it is worthwhile to examine the key variables and inputs upon which this determination will hinge. This testimony reviews these input assumptions and methodologies through a review of the analyses already submitted into the record, recommending that the Commission hold a workshop to reconcile major differences between the submitted analyses to better understand the resource need before approving significant ratepayer expenditures for emergency procurement. However, recognizing the need for urgent action and the Commission's proposed direction to the IOUs to return with proposed contracts by February 15, 2021, CalCCA recommends that authorized supply- and demand- solutions should not, cumulatively, exceed 1,073 MW, without further analysis. CalCCA also urges the Commission to make clear that responsibility for procuring additional resources under the December Ruling rests solely with the three IOUs.

Chapter 2 of this testimony, prepared by Michael Hyams, Matthew Langer, Mahayla Slackerelli, and Samantha Weaver, presents the response of various CCAs to certain questions posed in the December 18, 2020 Administrative Law Judge's ruling introducing a Staff Report and seeking certain information from parties (December 18 Ruling).[6] This section discusses the experiences of community choice program aggregators (CCAs) who have developed and implemented some form of "critical peak pricing", which may be useful in reducing load during constrained summer periods. The discussion identifies both the benefits of the programs and barriers encountered by the CCAs in implementing these programs. This Chapter also includes a discussion of recommendations for expanding electric vehicle participation in Demand Response (DR) programs and provides examples of existing CCA programs and pilots.

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[6] *Administrative Law Judge's Ruling Introducing a Staff Report and Questions to the Record and Seeking Responses from Parties in Opening and Reply Testimonies*, December 18, 2020, Attachment 1 at 4.

II. REVIEW OF NEEDS ASSESSMENT ANALYSES AND FINDINGS

The existing record, notwithstanding any additional analysis delivered in this round of opening testimony, comprises two analyses: one from the CAISO and one from SCE.[7] The CAISO and SCE analyses each represent valuable and significant contributions into the record and, while conceptually similar in their intent, take structurally distinct methodological approaches, use different input sources and, accordingly, differ significantly in their results. Given the focus within the CAISO analysis on September Hour Ending (HE) 20 (7:00 p.m. to-8:00 p.m. Pacific Standard Time), the hour which perhaps most acutely reflects net peak concerns, CalCCA's review of the analyses is also focused on September HE 20 and refers to values within that period unless otherwise stated. CalCCA concludes that, despite the value of both submissions, it is critical that the Commission move forward to reconcile the differences in assumptions and methodologies between the analyses prior to determining the level of need for emergency procurement in Summer 2021. Specifically, CalCCA strongly urges the use of an LOLE study consistent with SCE's approach, but notes below several areas where resource assumptions differ significantly with CAISO assumptions and may not accurately capture real world values, particularly assumptions for fossil resources, demand response, and other renewables (e.g. geothermal, biomass, biogas, etc).

CAISO's analysis reconstructs and updates the stack analysis exercise developed by ED staff in 2019 with key modifications. At a high level, CAISO's analysis estimates the available RA capacity in all hours of Summer Months (May-October), with specific focus on results for

[7] CalCCA wishes to acknowledge the transparency and spirit of collaboration of both the CAISO and SCE teams, and appreciates the time and effort taken to provide data and answer questions in the course of developing this testimony. While CalCCA has taken efforts to ensure the accuracy of the discussion below, the compressed time frame of this testimony has foreclosed the opportunity to review these results with the authors and some errors in interpretation may exist. CalCCA submits this testimony in the spirit of identifying areas for continued discussion and refinement of the analytical record.

Hour Ending (HE) 20 (7:00 p.m. to-8:00 p.m. Pacific Standard Time). CAISO modifies the stack by reducing the Qualifying Capacity (QC) of solar resources to zero beginning in HE 20, including planned resources, and including a range of estimates for import RA. CAISO compares the stack against both the current RA requirement, which includes a 15% Planning Reserve Margin (PRM), and a 20% PRM, which CAISO indicates is necessary to reflect latest available data on load forecast uncertainty and forced outage rates.

Assuming all available CAISO resources and an average level of import RA are shown by LSEs in 2021, CAISO's analysis finds a 1,073 megawatt (MW) shortfall in HE 20 for September 2021 based on the current 15% PRM. Utilizing a 20% PRM, as CAISO recommends, results in shortfalls from July through September ranging from 452 MW (August) to 3,316 MW (September). As a deterministic analysis, CAISO's needs assessment indicates the quantity of resources that would be necessary to avoid reliability events under specific, conservative conditions based on specific risk thresholds, represented respectively by the 15% and 20% PRM values. Said differently, CAISO's analysis does not provide an assessment of the probability or level of risk associated with achieving, for example, slightly less or slightly more than the prescribed PRM, but instead indicates whether the tested resource stack exceeds a pre-defined needs value. This approach, while less rigorous than other industry standard resource planning and reliability methods, was prominent in the 2019 IRP Procurement Track, and represents a more accessible work product for policymaker and stakeholder discussion – two factors which almost certainly contributed to CAISO's selection of this methodology for this urgent proceeding.

SCE's analysis, in contrast, tests a broad range of grid conditions, simulating 500 scenarios through its PLEXOS production cost modeling software. SCE's analysis uses resource data from SCE's Integrated Resource Plan (IRP), which reflects data from the 2019-2020 IRP Baseline Resource List[8] as well as expected new resources ordered in D.19-11-019, modeled as 1,650 MW of storage resources delivered in July and August 2021. SCE uses a stochastic LOLE study which varies load, fossil outages, and variable renewable resource production along defined probability distributions. SCE's input range includes the load, fossil outage rates, and variable renewable resource production values observed during the August and September heat storm events, as well as values both above and below observed values. Fixed values, including hydropower and imports, use IRP values with some modifications to better align with Summer 2020 observed conditions. SCE generated 500 scenarios using the stochastic variables described above and tested them through a PLEXOS production cost model of the CAISO system to determine the frequency and magnitude of unserved load events, defined as any hour during which available supply fell below the operating reserve margin.

SCE's analysis found that some scenarios – primarily scenarios with high fossil outages and low renewable input – included loss of load events during net peak hours (HE17-HE20) during July, August, and September. Still, in aggregate, SCE found that the LOLE did not exceed the industry standard reliability metric of 0.1 days per year, which would be equivalent to one day of lost load per ten years. However, SCE's finding of an LOLE of 0.09 suggests that the CAISO system only scarcely exceeds the 0.1 standard, and subtle modifications to the study's inputs could easily result in an LOLE conclusion which fails the 0.1 industry standard, as SCE observes in its comments.[9]

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8 https://www.cpuc.ca.gov/General.aspx?id=6442461894.

9 Southern California Edison Company's (U-338) Comments on 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, November 30, 2020, at 17.

In contrast to CAISO's analysis, which tests sufficiency under inclement weather and forced outage conditions, SCE's stochastic approach tests a broad range of conditions, including both "blue sky" and severe weather conditions. SCE's results should be interpreted as the likelihood of reliability events given the probability of underlying inputs – extreme load and lower-than-expected supply. Consequently, the LOLE determination hinges significantly on an accurate and precise probability distribution of the stochastic inputs, as well as correctly calibrated fixed inputs. SCE's probability distribution utilizes weather data designed to incorporate the covariance of high load and renewable output which should, in theory, link the probabilities of high load and low renewables both associated with extreme temperatures.

While these analyses are each useful and informative on their own, they are difficult to compare in equal terms given the conceptual differences noted above as well as the input differences discussed below. Moving forward, it would be worthwhile for the Commission to hold a workshop to align the assumptions of each analysis for better comparison and incorporate the best practices from each analysis; for example, applying SCE's stochastic approach to a resource list and set of stochastic inputs aligned between CAISO and SCE assumptions. The discussion below compares the assumptions and methods of the two studies, focusing on HE20 in September 2021 and provides recommendations to resolve differences in assumptions between the studies.

A. Resource Assumptions

While similar in intent, the two analyses have significant discrepancies in their baseline and planned resource assumptions, and only SCE varies resource availability across multiple scenarios. CAISO's baseline list is built from the 2021 NQC List with modifications and additional information from the Master Control Area Generating Capability List, the Announced

Resource Retirement and Mothball List, and CAISO interconnection queue for upcoming resources.[10] Solar resources are presumed to have zero effective capacity beginning in HE20. CAISO's analysis assumes 44,597 MW of available resources, which, with the average 5,921 MW of import RA capacity, results in 50,518 MW of resources being available to CAISO for dispatch at HE20 in September 2021.

SCE's resource list was developed from the IRP Baseline Generator Unit List for the 2019-2020 IRP cycle, modified to include new resources required by D.19-11-016 as well as other known modifications. SCE's analysis assumes a median of 48,857 MW of resources are available, including 5,480MW of imports, though this value is varied considerably through its stochastic analysis.

Table 1 below compares the resource assumptions across the two analyses, focusing on the most extreme values in SCE's analysis, assessed as the 99th percentile of reliability impact (highest values for load and resource outages, lowest values for renewable output).

Comparison of SCE and CAISO Resource Input Assumptions				
Fixed Resource Values				
Resource	**CAISO**	**SCE**	**SCE - CAISO**	**Notes**
Nuclear	2,280	2,277	-3	Negligible.
Hydro	6,588	5,100	-1,488	CAISO: NQC List, Incl Revised Hydro QC per D.20-06-031; SCE: IRP SERVM September capmax values
Other RPS	1,779	2,253	474	Reason for discrepancy not clear at this time.
Demand Response	1,453	2,195	742	Reason for discrepancy not clear at this time.
Battery Storage	2,468	2,552	84	Likely due to SCE assumption that all D.19-11-019 compliance through battery storage.
Imports	5,921	5,480	-441	Available imports uncertain until LSE month-ahead filings; both assumptions likely reasonable; CAISO average listed here.
Stochastic Resource Values (September, HE20, 99th Percentile of SCE Simulations)				

[10] Comments of the California Independent System Operator Corporation on Order Instituting Rulemaking Emergency Reliability, November 30, 2020, Attachment A, at 4-5.

Resource	CAISO	SCE (99th Percentile)	SCE - CAISO	Notes
Fossil	29,134	26,685	-2,449	CAISO uses full NQC and addresses outages in the PRM; SCE varies fossil resources with median production of 28,711 MW.
Solar	0	0	0	Note: Stochastic variable but all September, HE 20 values are zero.
Wind	895	0	-895	CAISO uses September ELCC for wind; SCE varies wind based on weather, with median wind production of 290MW in September, HE 20. 36% of scenarios have 0 wind in this hour.
Total Resources (September, HE20, 99th Percentile of SCE Simulations)				
Resource Totals (SCE 99th Percentile)	50,451	46,542	-3,909	Note that SCE's totals reflect expected high outage rates; CAISO's totals do not reflect outages which are instead addressed through the PRM.

Table 1: Overview of SCE and CAISO Assumptions

Overall, while CAISO has more resources in its resource stack than SCE's most extreme values, CAISO's resource stack does not reflect resource outages – these are instead reflected in CAISO's PRM. However, using CAISO's 10% outage rate from its proposed 20% PRM implies a resource total of 45,405 MW, which is approximately 1,136 MW lower than SCE's 99th percentile values. A discussion of specific differences and reasonableness of these assumptions is below.

1. Fossil Resources

CalCCA finds the fossil resource assumptions to be generally reasonable and consistent across the SCE and CAISO analyses, but highlights several retired resources which CalCCA understands SCE includes as a holdover from the IRP dataset. However, SCE and CAISO's treatment of forced outages, which represent a key factor in reliability risk, are pursued in very different manners.

CAISO's baseline list includes 29,134 MW, while SCE's includes 29,724 MW. CalCCA believes this difference is due primarily to SCE's inclusion of several resources which retired since the development of the IRP baseline list, representing 584 MW[11], included in greater detail in Appendix A. Reconciling this list would reduce the difference to approximately 6 MW, which likely reflects minor differences in resource values between the source documents.

Resource	Analysis	Total Capacity (MW)	Capacity With Outages (MW)	Notes
Fossil	CAISO	29,134	26,512	CAISO 9% forced outage rate in 15% PRM implies 91% availability
			26,221	CAISO 10% forced outage rate in 20% PRM implies 90% availability
	SCE	29,724	28,710	Median Fossil Outage: 1,014 MW
			27,736	90th Percentile Fossil Outage: 1,988 MW
			27,384	95th Percentile Fossil Outage: 2,340 MW
			26,685	99th Percentile Fossil Outage: 3,039 MW

Table 2: SCE and CAISO Fossil Resource Assumptions with Utilized and Implied Outage Rates

SCE approaches forced outages as a stochastic variable, testing 15,000 forced outage values across its 600 weather scenarios, while CAISO addresses forced outage rates in its PRM. To compare the implied fossil rate, CalCCA reduces CAISO's fossil list to 91% and 90%, respectively, to reflect the 9% and 10% forced outage rates assumed in CAISO's 15% and 20% PRM values. SCE's 99th percentile values (26,685 MW), which reflect the extreme weather captured in CAISO's conservative assumptions, are comparable to CAISO's implied 15% PRM fossil resource value (26,512 MW) and slightly above CAISO's implied 20% PRM fossil resource value (26,221 MW). Addressing the retired resource issue above would likely align SCE's values with CAISO's.

[11] Retired resources on SCE's resource list include the following Resource IDs: INLDEM_5_UNIT 1, 358 MW; CHINO_6_SMPPAP, 23 MW; COLGA1_6_SHELLW, 53 MW; MIDSET_1_UNIT 1 53 MW; SARGNT_2_UNIT, 57 MW; ANAHM_7_CT, 41 MW; GOLETA_6_GAVOTA, 0 MW; SBERDO_2_QF, 0.25 MW; STAUFF_1_UNIT, 0.1 MW.

2. Hydroelectric Resources

Both SCE and CAISO use reasonable assumptions for hydroelectric resources in light of water year variability and associated impacts on late summer hydroelectric production. CAISO utilizes the NQC list values for hydroelectric resources, totaling 6,588 MW. Some, if not most, of these resources likely utilize the revised hydro counting methodology adopted in D.20-06-031 which optionally allowed hydroelectric operators to reduce the NQC of their hydroelectric resources to an exceedance-based methodology. This methodology was noted, at the time of its adoption, to be a conservative methodology, and the Decision allowed generators to raise the NQC values of their facility through the year as more information became available. SCE utilizes monthly hydroelectric values from the IRP's SERVM database, totaling 5,100 MW for September.

3. Solar and Wind Resources

CalCCA finds the analyses' assumptions for solar and wind resources to be reasonable and generally consistent in magnitude, despite differences in approach. Variable renewable resources represent a significant source of uncertainty in any future-looking reliability assessment, and SCE and CAISO each approach this challenge differently.

Neither analysis includes any solar production in HE 20 in September, a reasonable assumption corroborated by CalCCA's review of historical renewable production below.

For wind, CAISO utilizes the September ELCC values, totaling 895 MW, while SCE incorporates wind as a stochastic variable, with a median value of 290 MW. However, it is worth noting that 36% of SCE's wind values during September, HE 20 reflect zero wind production.

Resource	Analysis	Full Capacity (MW)	Capacity With Outages (MW)	Notes
Wind	CAISO	895	814	CAISO 9% forced outage rate in 15% PRM implies lower effective fossil capacity by 9%
			806	CAISO 10% forced outage rate in 20% PRM implies lower effective fossil capacity by 10%
	SCE	6816	290	Median Wind Production
			0	36th Percentile (36% of simulations had no wind production in September, HE 20)

Table 3: Wind Production for SCE and CAISO Analyses in September, HE 20

SCE's approach to wind reflects a conservatism that may undervalue wind's contributions relative to historical performance. CalCCA reviewed historical variable renewable output from 2015 through October 2020 using 5-minute interval data from the CAISO OASIS server, represented in the graphic below. Note that CalCCA's analysis reflects energy production values over a period during which installed wind capacity grew from approximately 4.8GW to 6.3GW.[12]

Figure 1 below shows historical September solar and wind production represented with quartile box-and-whisker plots. Each box-and-whisker plot reflects the top 25% of observations (upper vertical line), median 50% of observations (box), median (horizontal line in box), and bottom 25% of observations (lower vertical line), as well as outliers (dots). CAISO's resource value assumptions are overlaid with a dashed line. A full monthly review from May through October is provided in Appendix B.

[12] Installed capacity based on Commercial Online Date from CAISO NQC List.

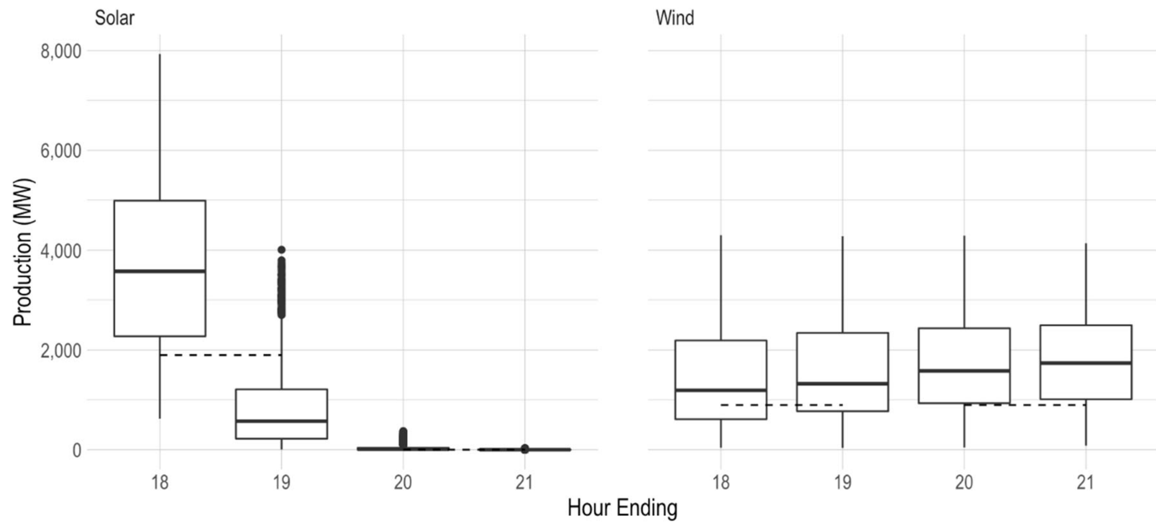

Figure 1: Solar and Wind Production in September
Hours Ending 18-21, 2015-2020 Historical Data

While wind has significant variability, and includes many values approaching zero, less than 25% of observations from 2015 through 2020 have produced below wind's QC value in HE 20, and its median production exceeds 1.5GW. It is unclear why SCE's distribution has such low values for wind production, but may reflect a conservative weather dataset within the IRP.

4. Import Resources

Import resource availability is likely the most significant source of uncertainty among RA resources for several reasons. First, unlike all other resources, available import resources cannot be simply tabulated based on an existing list or resource set. Second, it is not reasonable to assume that the same import resources will be shown by the same LSEs from year to year, and import resources may be more likely to be shown on Month Ahead filings relative to other resources. Third, changes to import resource eligibility taking effect in 2021 may result in significant changes in the quantity of firm import RA shown by LSEs in the coming year.

Finally, resource trends across the Western Interconnection may reduce the physical supply California's historical trading partners are willing to offer as firm capacity.

CAISO's analysis includes the Maximum Import Capability (MIC), which reflects the total physical transmission capacity into CAISO (10,805MW), as well as the monthly minimum, average, and maximum values of shown import RA over the prior six compliance years (2015-2020). SCE utilizes the IRP import constraint of 5,480 MW, based on historical levels of resource adequacy import contracting for LSEs. Recognizing the significant uncertainty regarding available RA imports, CalCCA instead focused its analysis on reviewing historical energy imports into the CAISO.

In general, CalCCA's analysis suggests that import resources have been dispatched in quantities consistent with the CAISO's three sensitivity values (minimum, maximum, and average). However, in contrast to must-take solar and wind resources, this simplified analysis of energy flows is complicated by the role of economic dispatch for import resources. Specifically, viewing historical energy production alone may obscure a deeper bench of available resources which were not called for economic dispatch during most hours. Understanding the extent of available import resources would require access to non-public bidding data that is not available to CalCCA.

As an alternate approach, CalCCA reviewed import behavior during the August and September heat wave as a proxy, assuming all available import resources were dispatched[13] and imported into CAISO. For context, the Preliminary Root Cause Analysis indicates that 2,600 MW to 3,400 MW of imports were bid into the CAISO day-ahead market above the August RA

[13] CalCCA utilized import energy values downloaded from CAISO's Today's Outlook tool.

requirement on August 14; however, a weather outage on the California Oregon Intertie reduced transmission capacity by approximately 650 MW.[14]

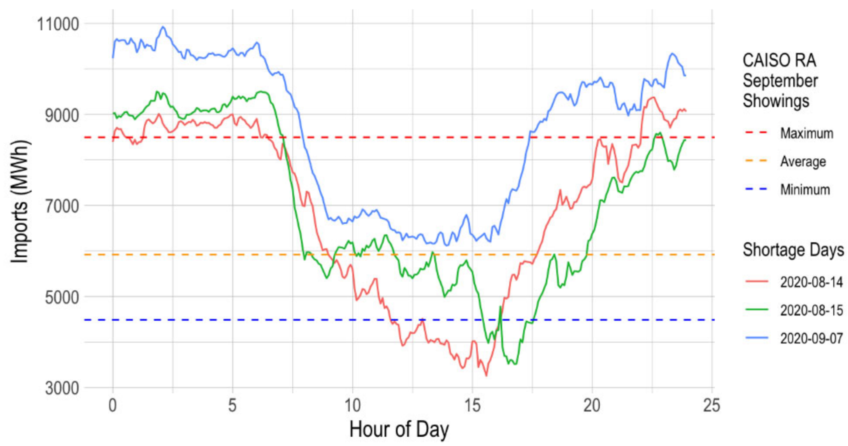

Figure 2: CAISO Net Imports During August and September Heat Storm Events

CalCCA's review of net imports during the August and September heat storm events suggests that it is reasonable to assume available imports may meet or exceed both CAISO and SCE's import values of 5,921 and 5,480 MW, respectively, given behavior observed during the August and September heat waves. However, a better understanding of future import availability in light of planned retirements throughout the Western Interconnection would be valuable for near-term planning.

5. Demand Response

The Demand Response values vary significantly between SCE and CAISO's analyses and, at this time, CalCCA does not have sufficient information to recommend a preferred assumption. CAISO sums Proxy Demand Response values from the NQC list (228 MW) and

[14] Preliminary Root Cause Analysis at 8-9. http://www.caiso.com/Documents/Preliminary-Root-Cause-Analysis-Rotating-Outages-August-2020.pdf.

2020 CPUC-credited investor-owned utility demand response without PRM (1,225 MW) for a total of 1,453 MW. SCE relies on the IRP baseline of 2,195 MW. The baseline DR assumptions in the IRP include existing IOU DR programs and interruptible pumping load. The peak load impact for each utility's programs is based on the April 1, 2018 Demand Response Load Impact Report. An additional 443 MW of interruptible pumping load is included as baseline DR capacity, which may be reflected in the SCE analysis but not the CAISO analysis. At this time, CalCCA does not have sufficient information to recommend a preferred assumption for demand response.

6. Battery Storage

At this time, the vast majority of battery storage in both analyses is still under development. While SCE's approach was justified given its limited visibility into planned resources, CalCCA recommends using CAISO's values given CAISO's unique access to interconnection queue data. Specifically, CAISO uses confidential data from its interconnection queue, indicating an additional 2,111 MW of storage, as well as 22 MW of wind (nameplate), and 320 MW of solar (nameplate) will be developed by September 2021. SCE assumes 1,650MW of new storage resources by September 1 pursuant to D.19-11-016, as well as 4,000MW of new solar resources.

This results in a cumulative battery storage value of 2,468MW for CAISO and 2,552MW for SCE in September 2021. SCE's analysis assumes that all LSEs will fulfill their D.19-11-019 obligations with battery storage, which likely drives the difference between the analyses.

B. Demand Assumptions

CAISO and SCE's analyses take very different approaches to managed load, and, generally speaking, CAISO's analysis appears to take a more conservative approach. Given the use of both analyses of the Independent Energy Policy Report (IEPR) 1-in-2 Mid-Baseline Mid-

AAEE ("Mid-Mid") managed net load forecasts, it is unclear at this time why the values for September HE 20 are so significantly divergent. This discrepancy (alongside structural differences in approach) likely plays a major role in the differing results of the two analyses and should be reconciled.

Demand and Reserve Margin (September, HE20, 99th Percentile Values)				
Resource	**CAISO**	**SCE (99th Percentile)**	**SCE - CAISO**	**Notes**
Managed Load	44,861	42,805	-2,056	SCE varies demand based on weather with a median rate of 36,012 MW for September, HE 20.

Table 4: SCE and CAISO Fossil Resource Assumptions with Utilized and Implied Outage Rates

CAISO's analysis utilizes the IEPR 1-in-2 Mid-Mid forecast of 44,861 MW in September HE 20; however, its 20% PRM analysis is intended to reflect a 1-in-5 forecast, which is associated with a 4% increase in HE 20 load to 46,655 MW.

SCE's analysis incorporates managed load as a stochastic variable ranging from 30,034 MW to 43,483 MW, and indicates the same IEPR 1-in-2 Mid-Mid dataset. While this range may initially appear broad, it is worth noting that SCE's analysis reflects values across the entire month of September, which has significant weather variability and includes many days of moderate temperatures and low cooling loads in addition to high cooling load days. To meaningfully compare analyses, it is more prudent to review SCE's extreme weather values. The top percentile of SCE's load in September, HE 20 ranges from 42,805 MW to 43,483 MW. SCE's values are also sourced from the IEPR forecast, with modifications to increase peak demand by 782 MW in August. Due to the compressed timeline, CalCCA has been unable to confirm why there is such a divergence between load values for September, HE 20 and notes that it is possible this may be resolved through improved understanding of the two analyses.

While there are outstanding questions regarding load in HE 20, CalCCA notes that SCE's narrative of its methodology indicates that the gross peak in 45% of its weather scenarios exceeded the IEPR 1-in-5 forecast, with 5% of its weather scenarios exceeding the 1-in-20 forecast. This suggests that, in the aggregate, SCE's analysis did significantly stress test the system with high demand values, despite the need for further discussion resolve questions regarding its assumptions for September net peak.

C. Results and Analysis

Consistent with their overarching methodological differences, CAISO and SCE diverge in their method for testing sufficiency and their corresponding results. In CAISO's analysis, sufficiency is achieved when the quantity of resources exceeds demand plus a PRM of 15% or 20%. In SCE's analysis, sufficiency is achieved as long as available resources exceed demand plus the CAISO operating reserve margin of 6%, with the remainder of the PRM "uncertainty" built into the stochastic variation of demand, fossil outages, and renewable production. This approach more accurately captures complex dynamics in which small changes in assumptions can result in substantial changes in the assessment of sufficiency.

Summary Results (September, HE 20, 99th Percentile for SCE Draws)

Resource	CAISO	SCE (99th Percentile)	SCE - CAISO	Notes
Resource Totals	50,518	46,542	-3,909	Note: SCE's resource stack internalizes forced outages.
Managed Load with 15% PRM (CAISO), 6% Reserve (SCE)	51,590	45,373	-6,217	CAISO demand augmented by 15% PRM; SCE demand augmented by 6% operating reserve margin.
Managed Load with 20% PRM (CAISO), 6% Reserve (SCE)	53,833	45,373	-8,460	CAISO demand augmented by 20% PRM; SCE demand augmented by 6% operating reserve margin.
Resource Buffer with 15% PRM (CAISO), 6% Reserve (SCE)	-1,072	1,169	2,308	CAISO demand augmented by 15% PRM; SCE demand augmented by 6% operating reserve margin.
Resource Buffer with 20% PRM (CAISO), 6% Reserve (SCE)	-3,315	1,169	4,551	CAISO demand augmented by 20% PRM; SCE demand augmented by 6% operating reserve margin.

Note: Values are presented here for discussion and verification purposes only. Due to structural differences in methodology, it is not appropriate to directly compare CAISO and SCE results. Specifically, SCE's resource stack reflects significant reductions from expected forced outages, while CAISO's resource stack does not. Inversely, CAISO's demand is augmented to reflect expected forced outages, while SCE's is not.

Table 5: Summary Results of CAISO and SCE Resource, Load Inputs

Table 5 summarizes data from the above sections on resource inputs and demand, though CalCCA notes that these summaries at not reasonably compared given structural differences in approach. For example, CAISO's analyses assume more resources are available given that forced outages are accounted for in the PRM rather than the resource stack. Similarly, SCE's "sufficiency" value is considerably lower given that the need for a PRM is transitioned into its accounting of resources.

CAISO's analysis, while binary in its assessment of "sufficiency," provides easily accessible and interpretable conclusions regarding the magnitude of potential shortages and the quantity of need moving into Summer 2021. While CAISO's conclusions using average imports and a 15% PRM may be a reasonable starting place for discussion of a needs assessment, it would be regrettable not to further develop CAISO's study into a more rigorous, stochastic analysis before utilizing its conclusions for procurement decisions.

Similarly, CAISO's recommended use of the 20% PRM bears further analysis before being used for resource investment decisions. CalCCA agrees with CAISO that the Commission should review the PRM as part of its overarching review of the RA program in R.19-11-009. Modifying the PRM to 20% – with a corresponding resource procurement impact of approximately 500 MW per percentage point – should be done only after a thorough analytical record has been developed to support such a determination.

Moreover, the PRM should be calibrated carefully using stochastic reliability analysis, similar to that done by SCE, to determine a PRM threshold which ensures reliability meets a standard acceptable to policymakers. CAISO's approach sums the approximate "buffer" for load uncertainty and resource outages with the operating reserve margin, while not altogether unreasonable in concept, approaches the problem from the wrong direction. Instead, the Commission should determine a desired reliability standard (e.g. less than 0.1 LOLE), test the existing resource fleet against the desired reliability standard using a well-calibrated, stochastic reliability modeling tool, and, iteratively, reduce or add resources until the desired LOLE standard is achieved, thereby determining an appropriate PRM. While this PRM is highly dependent on resource mix and may change over time, integrating this process with the IRP can reduce the uncertainty and frequency with which the PRM must be recalibrated.

SCE's LOLE analysis is methodologically consistent with the approach described above to determine a PRM. However, as noted by SCE, LOLE results can be susceptible to modest shifts in their input assumptions when constraints are present. For instance, the difference in demand response resource assumptions between CAISO and SCE – 742 MW – could have a major impact on the resulting LOLE value if a significant portion of the "sufficient" simulations were sufficient by 742 MW or fewer, as would the differences in baseline assumptions regarding fossil resources and load. Without further data regarding the distribution of the "sufficient" runs, it is unclear whether these modifications – or others – would move the resulting LOLE from 0.09 to a less desirable value, emphasizing the importance of vetting input assumptions and thoroughly reviewing results. Regardless, SCE's finding of 0.09 LOLE is encouraging and utilizing SCE's methodology with consensus inputs would improve precision for the needs determination.

D. Conclusion

Both CAISO and SCE should be lauded for their strong contributions into the record, as well as their novel consideration of emerging issues such as renewable variability and the growing risk of extreme weather. CalCCA supports the continued development of analytical tools for assessing reliability as California transitions away from conventional reliability resources.

In general, both CAISO and SCE make reasonable assumptions for resources and load, and use appropriate methodologies for considering resource sufficiency. CAISO's simpler methodological approach makes its analysis more accessible to policymakers and stakeholders, and it is reasonable to use CAISO's 15% PRM analysis as a starting point for "least-regrets" action by the Commission. Specifically, the Commission should endeavor to move forward in refining the analysis of need for Summer 2021 now, in anticipation of supply- and demand-side resources being brought forth by IOUs for Commission approval on February 15, as proposed in the January PD, to ensure the resources fit the need. Failing a more precise value becoming available, the Commission should consider CAISO's 1,073 MW result a ceiling for resource procurement for Summer 2021. Moving forward, this analytical approach – despite its precedent in D.19-11-016 – should not be considered rigorous enough on which to base significant procurement decisions. SCE's methodology is more appropriate for any procurement activity.

CalCCA encourages the Commission to hold a workshop to resolve outstanding discrepancies between the CAISO and SCE input assumptions, such as the differences in fossil, demand response, renewables, and managed load. Input differences, which collectively far exceed the expected scale of the need, should be reconciled and analyses revised prior to the approval of significant emergency procurement on the schedule indicated in the January PD.

III. ASSIGNMENT OF PROCUREMENT RESPONSIBILITY

In addition to considering the amount of a proposed change to the PRM, CalCCA reviewed how such a procurement obligation would be applied. CalCCA agrees with the Commission's framing of the procurement ordered by the December Ruling as a specific IOU-level requirement rather than a modification to individual LSE RA showings through a modified PRM for compliance year 2021. CalCCA urges the Commission to maintain the procurement obligation centrally with the IOUs, despite allocating costs across all customers. This obligation should not be subject to delegation or otherwise pushed down into individual LSE RA obligations this year. Specifically, this procurement should be considered incremental to individual LSE RA procurement and neither the compliance obligation nor the resource attributes should be allocated to LSEs, including IOU bundled portfolios, for the purposes of RA program accounting. Similarly, to ensure incrementality, this procurement should be tailored to minimize central procurement of resources which would otherwise be shown in LSE RA showings.

CAISO proposed in its comments an increase in the PRM that would flow through to individual LSEs.[15] However, the Commission can achieve the same reliability benefits via an IOU-procurement approach that does not modify the PRM requirements for individual LSEs, and, consequently, avoids significant disruption to on-going LSE efforts to procure RA for 2021. Indeed, setting the 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 implement its changes in time to address Summer 2021 reliability.

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[15] Comments of the California Independent System Operator Corporation on Order Instituting Rulemaking Emergency Reliability, November 30, 2020, at 2.

In addition, it would be disadvantageous to increase individual LSE obligations at the same time IOUs are directed to procure capacity through CAM under the December Ruling. Unsure of the exact amount of their CAM allocation of RA, LSEs will be unable to manage their portfolios efficiently. It will be difficult, if not impossible, for LSEs to accurately anticipate an LSE's CAM share of system RA in time for the LSE to act reasonably and responsibly to balance its portfolio. Perverse incentives could be created, as an LSE may decide to remain short until the allocation of the unknown centrally procured capacity occurs.

Thus, the IOUs' procurement obligation under the December Ruling should be clarified to remain an IOU-level requirement that may not be delegated to individual LSEs for this compliance year. However, for future years, if the Commission revises the PRM early enough to avoid significant disruption of LSE RA procurement, such as adopting a revised PRM for 2022, it would then be reasonable for resources procured under this order (as well as corresponding RA obligation) to be allocated to LSEs in the traditional manner utilized through the Cost Allocation Mechanism.

CHAPTER 2. WITNESSES MICHAEL HYAMS, MATTHEW LANGER, MAHAYLA SLACKERELLI AND SAMANTHA WEAVER

I. DEMAND-SIDE SOLUTIONS

The Administrative Law Judge's December 18, 2020 ruling,[16] included "Final Staff Proposals and Guidance to Parties" posing several questions to stakeholders regarding Critical Peak Pricing (CPP) marketing, design, and expansion to Non-IOU LSEs. Among these questions, Staff Question 6 seeks information regarding CPP-like programs implemented by

16 *Administrative Law Judge's Ruling Introducing a Staff Report and Questions to the Record and Seeking Responses from Parties in Opening and Reply Testimonies*, December 18, 2020, Attachment 1, at 4.

Community Choice Aggregators. Staff Question 7 seeks responding CCAs' experience regarding communication strategies to support the programs. In addition, the Final Staff Proposals and Guidance to Parties seeks information regarding electric vehicle (EV) programs. Witnesses from each of CleanPowerSF, Clean Power Alliance (CPA), Peninsula Clean Energy Authority (PCEA), and Redwood Coast Energy Authority (RCEA) provided information in response to these questions.

A. CleanPowerSF – Michael Hyams

This portion of testimony is provided by Michael Hyams, Director, CleanPowerSF, on behalf of CalCCA Mr. Hyams' qualifications are set forth in Attachment B.

1. Question 6: Program Design, Benefits, and Barriers

CleanPowerSF has implemented its Peak Day Pricing (PDP) Pilot program for two seasons (May to October 2019 and July to October 2020). This voluntary program incentivizes large commercial customers to reduce their electricity consumption between 4-8 p.m. on event days. The program is in the family of Critical Peak Pricing initiatives in that it uses customer price signals on a small number of days determined by grid and market conditions. Rather than being structured as a tariff with charges and credits on monthly customer bills, CleanPowerSF's PDP program offers one end-of-season incentive (bill credit). The incentive represents the net customer benefit of program credits and peak-day charges, calculated in parallel accounts, while the customer pays their monthly bill based on their normal tariff. Enrolled customers receive notices by text and email one day ahead of called PDP event days. The program mirrors PG&E's called event days, which are typically the hottest days of the summer in Northern California. Customer feedback surveys were conducted following the 2019 season but have not yet been conducted for the 2020 season. These interviews have informed CleanPowerSF's program design

– as has the previous experience of other CCAs, RCEA and East Bay Community Energy (EBCE).

CleanPowerSF offered bill protection for both of its PDP seasons. Based on customer feedback in 2019, customers view bill protection as a critical aspect of the program. Across the board, participants noted that without bill protection, they would not have participated in the program, as they would not be comfortable with the risk of additional charges.

Following the 2019 season, customers reported a very positive experience with the PDP program and were motivated to participate because they saw the program as aligned with their company's sustainability goals. Participation in the program bolstered customers' positive impression of CleanPowerSF as a whole. Additional benefits to non-IOU LSEs include:

- The voluntary enrollment PDP model (compared to a tariff approach) offers incentives and increased awareness for large customers to respond to peak days, while not requiring re-tooling of billing software, or extensive rate design. This approach of parallel price signals with separate program accounting may be a more achievable strategy for CCAs to be responsive to the grid constraints in the near-term.
- This PDP program approach offers CCA customers parity with the opportunity for credits for load responsiveness that IOUs offer through standard tariffs (which have PDP built-in).
- CleanPowerSF's PDP provides an avenue for customers and the CCA to be in alignment with the state's broader public purposes, including reliability and affordability.

- The flexibility of this PDP program approach allowed CleanPowerSF to be nimbler in shifting to a more useful PDP peak than a billing-based approach. Shifting the event day window to 4-8 p.m. from PG&E's 2-6 p.m. window was received very positively; commercial customers felt that this time period was much easier to respond to than the middle of the day.

Importantly, other potential benefits are still to be determined, especially the effectiveness of the program in impacting the LSE's peak day demand, and the program's cost-effectiveness as a resource. CleanPowerSF's PDP pilots to date have been modest in scale and focused on testing operational readiness. A scaled-up program would be needed to evaluate cost-effectiveness.

While the program has yielded clear benefits, CleanPowerSF has also encountered barriers in the implementation process.

- Data Quality: CleanPowerSF has found that a thorough quality assurance process is necessary if depending on PG&E's ShareMyData interval data to perform incentive calculations. During both of CleanPowerSF's program seasons, issues pertaining to data quality and availability from interval data pulled via ShareMyData arose.
- Limited Discretionary Load: While customers preferred the 4-8 p.m. PDP period, most reported that their energy use typically drops after 6 p.m. as operations shut down, so in effect they only managed discretionary load from 4 p.m. to 6 p.m. Of note, many customers indicated that they felt that they have limited discretionary load and that further reductions would be difficult to achieve without sacrificing occupant comfort or critical operations. This was particularly true among

customers who had previously made energy efficiency upgrades. Targeting the program to larger commercial and industrial customers may be appropriate since early results indicate that a few large customers provided most of the load shift/ curtailment.

CleanPowerSF is still evaluating the value of technical assistance and feedback offered for the first time in the 2020 program season. Of the several newly enrolled large customers who were offered modest technical support, none took advantage of the technical support. CleanPowerSF's experience may suggest that offering technical support is not a necessary component to CPP programs targeted at large commercial customers. That said, 2020 experience may not be representative; in a COVID-tinged season, minimizing contacts, or simply managing staff bandwidth, could have contributed to opting out of tech assistance. Also, the program is still evaluating how worthwhile are the event-day feedback reports, offered for the first time in the 2020 season. Data permissions, secure communication methods, and data quality all presented some level of challenge. End of season analysis is underway to determine if this investment was valuable.

2. Question 7: Communications Strategy

CleanPowerSF has found that a robust communications strategy is necessary to educate and recruit large commercial customers to participate in its PDP Pilot program. When recruiting participants for PDP, it is essential to connect directly with the actors at the organization that will lead the energy reduction efforts and that are authorized to make decisions related to the account; typically, this is the building management team. CleanPowerSF has found that high-touch outreach, such as one-on-one conversations, throughout the enrollment process is essential. CleanPowerSF has also observed that sustainability-type contacts are beneficial to connect with as they serve as advocates of the program and assist with obtaining internal buy-in for the organization to participate in the program.

B. Clean Power Alliance- Matthew Langer

This portion of testimony is provided by Matthew Langer, Chief Operating Officer, Clean Power Alliance (CPA), on behalf of CalCCA. Mr. Langer's qualifications are set forth in Attachment C.

1. Question 6: Program Design, Benefits, and Barriers

In 2019, CPA began its Peak Management Pricing (PMP) pilot program. PMP is a demand response program, similar in design to the CPP programs offered by large electric IOUs, that encourages commercial and municipal customers to voluntarily power down appliances, electronics, air conditioning, or other equipment during peak heat days. Participating customers receive bill credits during the summer months of the program (June - September) in exchange for being charged a premium for energy consumed during peak hours (4:00 - 9:00 p.m.) on "PMP Event Days". PMP Event Days are often the hottest days of the year with high energy consumption and only occur on non-holiday weekdays, with a maximum of 12 event days per year. Participants are notified via email or text up to 24 hours in advance of an event. Every customer that elected to participate in PMP also enrolled in CPA's Bill Protection program. Bill Protection customers receive a bill credit at the end of their first calendar year on PMP if they paid more than they would have otherwise paid on their regular rate.

CPA is cautiously optimistic that programs such as PMP can provide load management benefits when scaled properly but customer enrollment into PMP has been challenging. CPA's PMP requires commercial customers to opt-in to the program. CPA has performed limited mass marketing and engaged individual customers but has received little response to these outreach efforts. Enrollment in the first year of the PMP pilot program was small and declined in the second year of the PMP pilot, when customers were asked to re-enroll. Many potential customers conveyed that they are unable to control their loads during events due to operational considerations as a reason for not enrolling in the program, even when Bill Protection was offered to protect customers from downside risk.

CPA has identified some potential solutions that could enhance enrollment and the load management benefits offered by CPP-like programs. First, enhanced customer outreach through key accounts representatives emphasizing the potential benefits of the program in individual conversations could yield higher enrollment. Second, non-IOU LSEs must ensure they have reliable and updated contact information for their commercial customers in order to provide notice of demand response events. Finally, non-IOU LSEs might benefit from training on CPP rate-design to enhance the cost-effectiveness of their CPP-like programs. Workshops hosted by the CPUC that include large IOUs and CCAs with effective CPP programs could benefit rate-design and program design for other LSEs looking to create or enhance their own programs.

2. Question 7: Communications Strategy

Limited data from CPA's two pilot years have shown that some customers either don't have the capability to manage loads during events or don't understand the PMP program well enough to respond. Additionally, CPA has seen low engagement levels from commercial customers through traditional mass market techniques such as direct mail. Direct, customized, and targeted outreach and tools to educate commercial customers of the availability and benefits of these programs would enhance engagement with an opt-in program model.

C. Redwood Coast Energy Authority- Mahayla Slackerelli

This portion of testimony is provided by Mahayla Slackerelli, Account Services Manager, Redwood Coast Energy Authority (RCEA), on behalf of CAlCCA. Ms.Slackerelli' s qualifications are set forth in Attachment D.

1. Question 6: Program Design, Benefits, and Barriers

RCEA has provided a Peak Day Pricing Alternative (PDPA) program to customers for four seasons, each summer since the launch of the CCA in 2017. The program was designed to emulate the PG&E PDP program, allowing customers that realize cost savings from the IOU program to continue to receive those benefits after switching to RCEA's service.

RCEA's PDPA has historically mirrored PG&E's PDP program in structure. Under the program design that was used up to and including the 2020 season, commercial customers who were previously in the IOU PDP program were offered participation in the RCEA program on a voluntary basis. During the PDP season of May 1 through October 31, RCEA sent out emails and text messages to customers that signed up for the program the day before each event day as called by PG&E, prompting the customers to reduce or shift electric load during the 2:00 pm to 6:00 pm window. At the end of the season, RCEA analyzed whether the customer would have done better on the IOU PDP program. If the customer would have realized financial benefit from PG&E's PDP, RCEA provided them with a bill credit for the difference, making the customer whole. In this way, the program may have incentivized some load shifting or conservation, but without programmatic consequences for ignoring the alert and maintaining business as usual.

While the previous seasons' PDPA incentivized customers to shift load on event days, the goal of the program was to retain customer participation in the CCA. Given this, RCEA did not evaluate the impacts of the program on reducing its peak demand. In 2020, RCEA staff decided to restructure the program for the 2021 season with a new goal of reducing demand on days with the highest wholesale energy costs, thereby decreasing costs for RCEA and reducing load on the grid when it is critically needed. The August 2020 heat events affirmed RCEA's determination to improve the program and shift more load. The 2021 PDPA program is currently under development but will still be largely structured like PG&E's PDP. Beginning this year, it will include credits for load shifting and charges for failing to comply, and will align the peak event hours better with the actual evening summer peaks on the grid. Customers who elect to be in the program will see those credits and charges on their monthly bills rather than a true-up at the end of the season. This is the first year that RCEA will have access to billing quality usage data with enough regularity to implement monthly credits. Although peak events will now be scheduled independently of PG&E's peak days, RCEA plans to maintain the practice used by PG&E of committing to a specific limited number of peak events per season in order to limit the program's impact on customers.

RCEA is planning on pairing the 2021 PDPA with rebates for demand response controls and offering consultation on load management to select customers with the most opportunity for reducing demand during critical hours. This year will be a pilot season for those additional services with the intention of expanding them in following years pending successful deployment. RCEA has also launched a Behind-the-Meter Distributed Resource Adequacy (BTM DRA) program, which is expected to work in tandem with the PDPA program to curtail load during critical grid reliability events. Although the exact operational date and volume of capacity to be installed under the BTM DRA program are still being determined, RCEA expects to bring 1-5 MW of BTM RA online as a Proxy Demand Resource within the next few years.

RCEA is also contributing to grid reliability starting in summer 2021 through procurement of demand response via a resource adequacy contract with Leapfrog Power, Inc. (Leap). The contract will ensure RCEA's compliance with its procurement obligation for incremental capacity under the CPUC's D.19-11-016. The demand response aggregation will provide 5.5 MW of net qualifying capacity for a 10-year term, with delivery set to begin June 1,

2021. Leap's portfolio includes customer loads throughout CAISO, including some within RCEA's own service area.

2. Question 7: Communications Strategy

RCEA's PDPA communication strategy has been focused on providing program information to eligible customers and alerts for event days. RCEA has been a trusted energy advisor to Humboldt County since before the launch of the CCA program. Continuing in that role, RCEA is planning to help commercial customers respond to incentives from the restructured PDPA in 2021. This would mean providing broad messaging on program opportunities and working directly with facility managers to identify loads suitable for demand response. In previous seasons, where RCEA's program goal was to limit customer opt-outs, marketing effort was minimal. For the 2021 season with its more diverse and ambitious program goals, RCEA plans to increase marketing effort in order to maximize program participation.

D. Expanding Electric Vehicle (EV) Participation in DR Programs- Samantha Weaver

This portion of testimony is provided by Samantha Weaver, Principal Regulatory Analyst, East Bay Community Energy (EBCE), on behalf of CalCCA. Ms. Weaver's qualifications are set forth in Attachment E.

CalCCA supports leveraging the flexibility and potential of EV loads and encourages the Commissions to pursue strategies that maximize the use of vehicle-grid integration (VGI) to support Summer 2021 reliability, but only to the extent actions are feasible in the short-term. In response to the questions in Attachment 1 related to expanding EV participation in DR programs, CalCCA notes that the Final Report of the California Joint Agencies Vehicle-Grid Integration Working GroupVGI Working Group) is the result of collaboration between 85 organizations for over more than a year and provides distinct, actionable recommendations, including actions the

Commission could undertake to advance VGI in the short-term.[17] The Working Group recommendations that address programs, rates and incentives[18] include:

- Create an "EV fleet" commercial rate that allows commercial and industrial customers to switch from a monthly demand charge to a more dynamic rate structure;
- Enable customers to elect BTM load balancing option to avoid primary or secondary upgrades, either if residential R15/16 exemption goes away, or as an option for non-residential customers;
- Consider coordinated utility and CCA incentives for EVs, solar PV, inverters, battery storage, capacity, and EV charging infrastructure to support resilience efforts in communities impacted by PSPS events;
- Allow V1G and V2G to qualify for SGIP to level the playing field with incentives for other DERs, but V1G would get less incentive compared to V2G based on permanent load shift logic;
- Incentive(s) for construction projects with coincident grid interconnection and EV infrastructure upgrade;
- Enable customers, via Rules 15/16 or any new EV tariff, to employ load management technologies to avoid distribution upgrades, and focus capacity assessments on the Point of Common Coupling; and
- Create incentives for charging infrastructure for new public parking lot construction projects.

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[17] D.20-12-029, Appendix A, Final Report of the California Joint Agencies Vehicle-Grid Integration Working Group, June 30, 2020. Available at: https://gridworks.org/wp-content/uploads/2020/07/VGI-Working-Group-Final-Report-6.30.20.pdf.

[18] *Id.* at 10.

CalCCA recommends this list be prioritized based on actions that are feasible to implement in the near-term. Specifically, to further incentivize demand-managed EV charging, CalCCA supports the VGI Working Group's and Marin Clean Energy (MCE), EBCE, and PCEA (Joint CCAs) recommendation to expand SGIP eligibility to include vehicle-to-grid use cases. To best achieve this CCAs have suggested that the Commission create a new budget category under SGIP to provide incentives for demand-managed EV charging, V2G and vehicle-to-building compatible EV supply equipment systems.[19,]

Finally, several CCAs have already developed or deployed managed charging pilots and DR programs for EVs. These existing programs include[20]:

- CPA: "Power Response" program which enables EV DR for commercial customers;
- Silicon Valley Clean Energy: "GridShift" EV Charging pilot collaborated with a software company on 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 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;
- Sonoma Clean Power (SCP): "GridSavvy" community program includes more than 2,900 smart devices, including 800 Level 2 EV charging stations. SCP dispatched this "virtual power plant" fleet in August and September to coincide with CAISO flex alerts;

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[19] *Id*. at 10, 38; *See* R. 20-05-012, Opening Comments of the Joint CCAs in Response to Scoping Memo Questions, September 16, 2020, at 13.

[20] 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".

- Pioneer Clean Energy (PCE): " FlexCharging Pilot” is a vehicle telematics-based software for residential EV charging. PCE is currently evaluating the effectiveness of various forms of customer incentives to shift more charging off peak.

CCAs look forward to working with the Commission on actions that bolster their existing efforts and create new opportunities to maximize the use of VGI to support Summer 2021 reliability.

<u>Appendix A</u>

Fossil Resource Alignment Between SCE and CAISO Analyses

CalCCA reviewed the thermal resource lists used by SCE and CAISO. While most resources were aligned, CalCCA identified 9 resources in SCE's dataset which were not identified in CAISO's dataset. Of these, 8 are listed as retired in CAISO's latest Announced Retirement and Mothball List.[21] These retired resources total 583.96 MW and are listed below. One additional resource within SCE's dataset was not identified in CAISO's dataset or the Announced Retirement and Mothball List, totaling .01 MW.

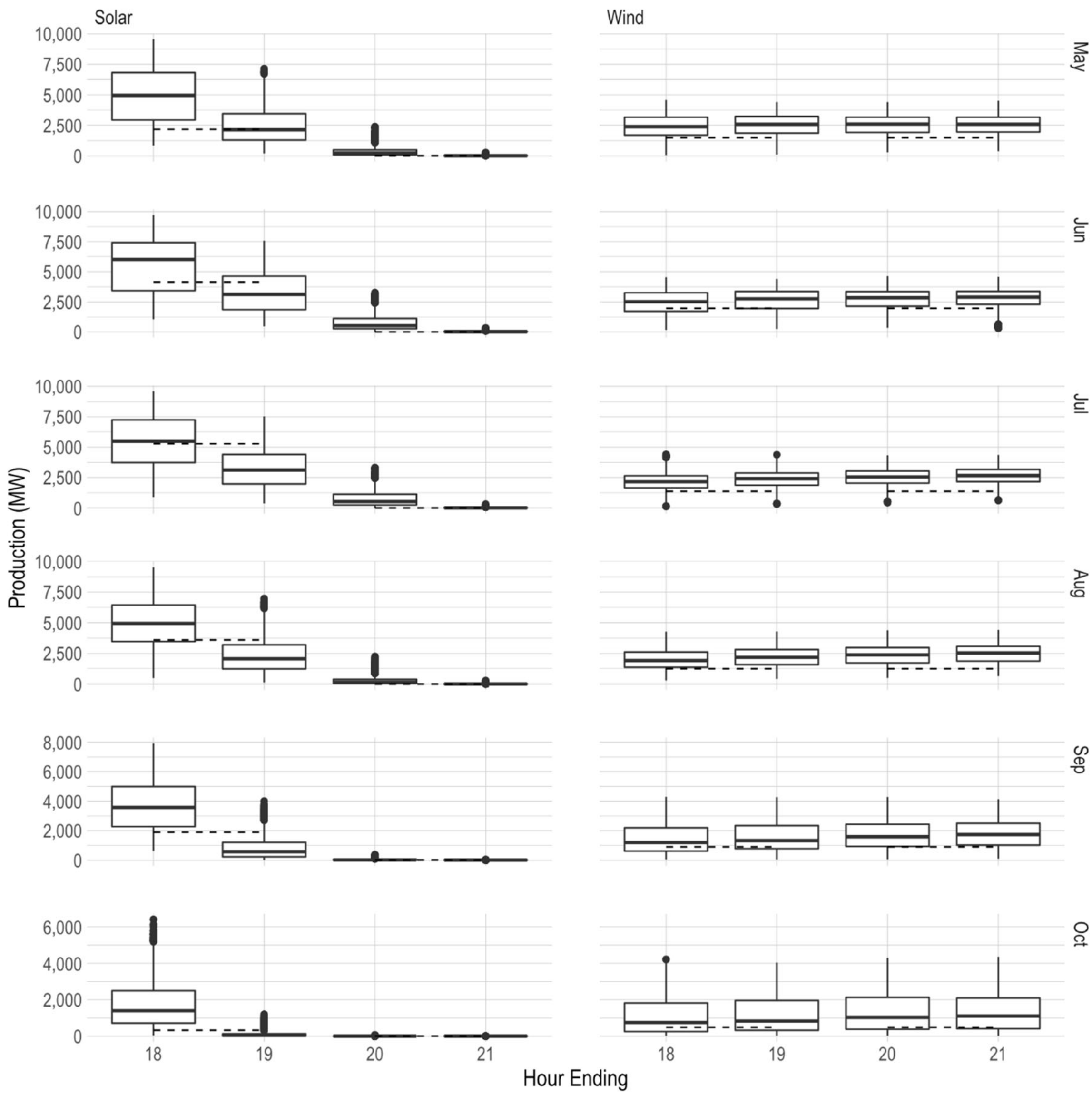
Resource Name	Type	Status	Offline Date	NQC (MW)
INLDEM_5_UNIT 1	CCGT1	Retired	1/15/2020	357.39
CHINO_6_SMPPAP	Peaker1	Retired	9/6/2019	22.78
COLGA1_6_SHELLW	CHP	Retired	12/31/2016	52.9
MIDSET_1_UNIT 1	CHP	Retired	12/31/2016	52.9
SARGNT_2_UNIT	CHP	Retired	12/31/2016	57.1
ANAHM_7_CT	Peaker1	Retired	6/30/2020	40.64
GOLETA_6_GAVOTA	CHP	Retired	11/2/2019	0
SBERDO_2_QF	CHP	Retired	6/30/2020	0.25
STAUFF_1_UNIT	CHP	Unknown		0.01
Total Retired				583.96
Total Unknown				0.01

21 December 18, 2020 Announced Retirement and Mothball List http://www.caiso.com/Documents/AnnouncedRetirementAndMothballList.xlsx

<u>Appendix B</u>

Historical Renewable Resource Output

Appendix B compares historic evening solar and wind resource output from May through October in Hours Ending 18-21 against NQC values utilized in the CAISO analysis. Data reflects 5-minute interval data from the CAISO OASIS server from 2015 through 2020.



Appendix A

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MIDSET_1_UNIT 1	CHP	Retired	12/31/2016	52.9
SARGNT_2_UNIT	CHP	Retired	12/31/2016	57.1
ANAHM_7_CT	Peaker1	Retired	6/30/2020	40.64
GOLETA_6_GAVOTA	CHP	Retired	11/2/2019	0
SBERDO_2_QF	CHP	Retired	6/30/2020	0.25
STAUFF_1_UNIT	CHP	Unknown		0.01
Total Retired				583.96
Total Unknown				0.01

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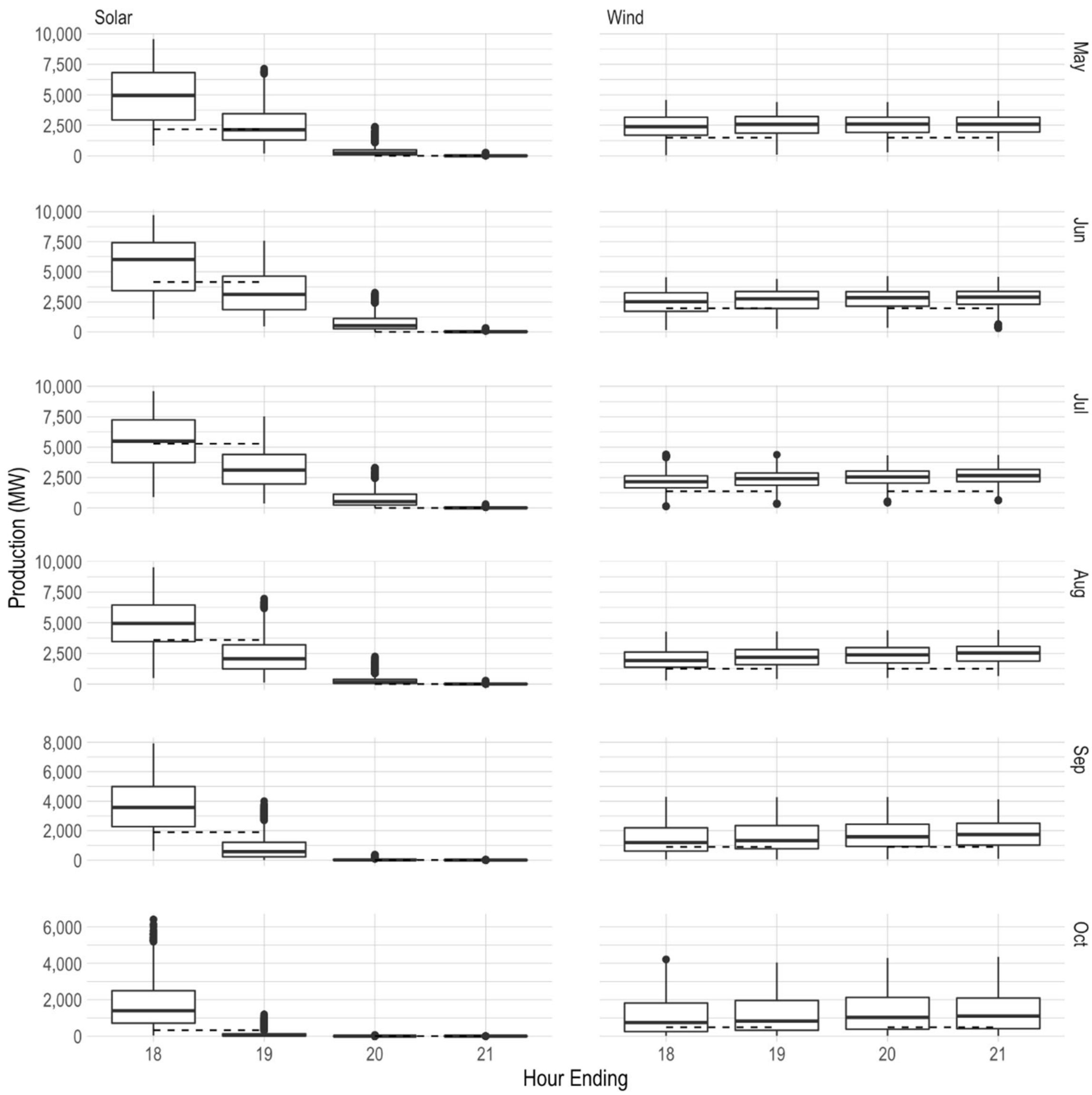

Attachment A
Nick Pappas

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SUMMARY

Clean energy industry leader with 10+ years of experience developing and shaping California policy in the legislative and regulatory arenas. Mission-driven; focused on the development and implementation of robust, functional, and lasting solutions to the global climate crisis.

EXPERIENCE

California Community Choice Association (CalCCA) **Sacramento, CA / San Francisco, CA**
Director of Strategic Initiatives and Outreach 1/2019 - Present

- Support the institutional development of CalCCA as an emerging trade association, with particular emphasis on building CalCCA's regulatory, legislative, and market analysis programs.
- CalCCA lead for procurement policy issues (Integrated Resource Planning, Resource Adequacy), responsible for policy analysis, internal position development and consensus building, drafting of regulatory filings, policymaker advocacy, and stakeholder outreach.
- Chair CalCCA's Procurement Working Group (35+ weekly participants), responsible for leading discussion and building consensus on complex, novel, and challenging policy issues.
- Manage CalCCA's data team responsible for collecting CCA data and developing meaningful analysis for internal discussion, peer benchmarking, continuous improvement, and incorporation of quantitative results into policy advocacy and communications.
- Lead CalCCA's efforts to identify and address mid- to long-term market and policy issues facing CalCCA members, educate internal partners, and manage efforts to design procurement and policy solutions to address long-term industry challenges.
- Support on-going member education through development of webinars, roundtable discussions, and conference panels on key issues impacting CalCCA members.

UC Davis Energy Graduate Group (UCD) **Davis, CA**
MS Student, Energy Systems & Graduate Student Researcher 9/2016 - 1/2019

- Augmented public policy career with interdisciplinary deep dive into "hard skills" – theory, methods, data analysis, and other aspects of economics, policy, and engineering research related to energy, transportation, and climate.
- Conducted research on electric sector reliability policies, climate policy design, and clean transit under faculty advisors from Economics (Prof. James Bushnell) and Civil and Environmental Engineering (Prof. Alissa Kendall).

Energy and Environmental Economics (E3) **San Francisco, CA**
Summer Associate (Internship) 6/2018 - 9/2018

- Led client project assessing policy strategy options for utilities confronting customer choice market transition; presented final deliverables to client senior executive and team.
- Contributed data visualization, financial modeling, and consumer research for joint utility project examining economic and environmental benefits of building electrification in California.
- Presented twice for "E3 Lunch Talk" series, discussing research on retail choice in US electric markets and utility regulatory and legislative policy structure in California, respectively.

Southern California Edison (SCE) **Sacramento, CA**

Senior Legislative Advocate | Legislative Advocate 12/2012 - 5/2016

- Managed SCE engagement on dozens of bills and budget proposals, including major legislation on renewable resource development, rate design, demand-side management, transmission and distribution reliability, distributed generation programs, and other key areas.
- Developed internal consensus on bill positions, drafted position letters, provided oral testimony in committees and advocacy meetings, and negotiated amendments to improve outcomes for SCE customers, operations, and shareholders.
- Developed and presented SCE's annual legislative education program designed to improve technical understanding of the electric industry among policymakers and increase awareness of emerging trends related to resource procurement, customer choice, and grid investment.
- Engaged policymakers and stakeholders with an earnest interest in developing viable, cost-effective, market-based solutions to their policy concerns, developing lasting relationships and mutual trust with legislative and agency staff, industry, and non-profit advocacy organizations.

California State Assembly, Office of Assemblymember Nathan Fletcher **Sacramento, CA**

Legislative Director | Jesse M. Unruh Assembly Fellow 10/2010 - 12/2012

- Developed an insider's view of energy politics as the advisor to a key member of the Assembly Committee on Utilities and Commerce during the formative years of California's clean energy policies (e.g. cap and trade implementation, 33% Renewables Portfolio Standard, net metering).
- Met with hundreds of community and policy advocates on issues ranging from healthcare funding and auto insurance requirements to industrial cogeneration and community solar.
- Managed the legislative agenda and bill analysis for thousands of committee and floor votes.

SKILLS AND ATTRIBUTES

- **Legislative and Regulatory Advocacy:** Seasoned, respected energy policy expert with years of experience testifying in legislative committees, drafting regulatory filings, and negotiating the finer points of legal and technical detail with stakeholders and policymakers.
- **Energy and Climate Subject Matter Expert:** Deeply versed in the science, engineering, economics, and policy frameworks governing the energy sector; capable of succinct translation of technically and legally complex issues for executive and political audiences (and vice versa).
- **Leadership:** History of success leading large and divergent groups to consensus on complex issues, incorporating and resolving competing viewpoints on path to unified team vision.
- **Market Analysis and Data:** Trained in energy economics and modeling; familiar with core regulatory modeling processes and tools, relevant state and federal datasets, and essential methods of industry and academic analysis of wholesale electric systems.
- **Writing and Communications:** Skilled communicator and editor across all modern written and visual formats, from didactic presentations and position papers to simple meeting agendas.
- **Programming:** Trained in R (intermediate/advanced), Excel (intermediate), Python (beginner).

EDUCATION

M.S. Energy Systems – University of California, Davis 2016-2018

Jesse M. Unruh Assembly Fellowship – Sacramento State University 2010-2011

B.A. Economics; Minors Writing, Latin American Studies – University of California, Davis 2006-2010

Attachment B

Michael A. Hyams
Director, CleanPowerSF
525 Golden Gate Avenue, San Francisco. CA. 94102 mhyams@sfwater.org

PROFESSIONAL EXPERIENCE

City and County of San Francisco Public Utilities Commission (SFPUC)
Director, CleanPowerSF (Community Choice Aggregation Program) Dec 2015-Present
Lead team responsible for planning, development, implementation and operation of CleanPowerSF, San Francisco's Community Choice Aggregation Program, with an annual budget in excess of $200 million per year. Responsible for developing business and operating plans, power portfolio management, complementary customer programs, hiring and managing staff, developing schedule and identifying all resources required to support CleanPowerSF implementation and operation.

City and County of San Francisco Public Utilities Commission (SFPUC)
Interim Director, Policy and Administration Group and Community Choice Aggregation Program March 2015-Nov 2015
Oversee the work of the Power Enterprise's Policy and Administration Group, including planning, monitoring, evaluating and coordinating the work of its various subdivisions including Regulatory and Legislative Affairs and direct the development of a Community Choice Aggregation Program for San Francisco.

City and County of San Francisco Public Utilities Commission
Acting Manager, Regulatory and Legislative Affairs May 2013-March 2015
Manage team responsible for ensuring compliance with electric utility regulations; monitoring, evaluating and planning for regulatory and/or legislative changes affecting the Department; and representing the policy and business interests of the SFPUC and its customers and residential and commercial energy ratepayers of San Francisco in Local, State and Federal regulatory and legislative forums.

City and County of San Francisco Public Utilities Commission
Utility Specialist Feb 2012-May 2013
Provided regulatory/legislative support to the SFPUC's Power Enterprise; monitored and intervened in state regulatory and legislative proceedings; supervised consultants work on transmission cost containment and California ISO stakeholder processes; and supported Power Enterprise's long-term planning efforts.

Port Authority of New York and New Jersey (PANYNJ)
Senior Energy Analyst July 2010-Jan 2012
Provided strategic planning, analytical, technical and research support for the PANYNJ Energy Program, including budgeting and demand forecasting of agency energy use and cost; managed team of consultants developing guaranteed energy savings projects with approx. $20 million in proposed upgrades at three Port properties; monitored and intervened in energy regulatory and policy proceedings; analyzed energy data for project assessment and development.

Columbia University Center for Energy, Marine Transportation and Public Policy
Research Associate and Acting Director, Urban Energy Program July 2009-July 2010
Responsible for on-going program design, research and other program activities; served as lead author and project manager of a multi-institution research team in the preparation of a white paper and policy roadmap for distributed energy "micro-grids" for New York.

National Photovoltaic Construction Partnership (NPCP)
Researcher Jan 2008-Sept 2008
Assisted NPCP Director in developing a proposal for a Renewable Energy Extension Service for New York State; conducted a range of energy research projects in support of NPCP's solar energy development business, including market and regulatory changes.

City and County of San Francisco Public Utilities Commission
Utility/Regulatory Analyst Dec 2003-Sept 2007
Provided regulatory support to the SFPUC's Power Enterprise; monitored and intervened in state regulatory proceedings; project managed long-term planning efforts; analyzed energy data; collaborated with stakeholders to design new load-serving programs.

EDUCATION

Columbia University, School of International and Public Affairs New York City, NY
Master of Public Administration, International Energy Management & Policy May 2009

University of Oregon Eugene, Oregon
Bachelor of Arts, *Magna Cum Laude* December 2000

Attachment C

Matthew H. Langer

EXPERIENCE

Clean Power Alliance of Southern California
Chief Operating Officer May 2018 –Present
Responsible for key operational business areas at the largest CCA in California, including energy procurement, regulatory affairs, customer programs, key accounts, rate setting, non-energy procurement and strategic planning

Southern California Edison Rosemead, CA
Principal Advisor, Energy Procurement Strategy January 2018 –April 2018
Leading efforts to develop strategies for optimizing SCE's energy portfolio including energy, capacity, RECs, GHG and other products; working with stakeholders to devise a fair cost-allocation mechanism for entities pursuing Community Choice Aggregation (CCAs)

Principal Advisor, Distribution Special Projects January 2017 – January 2018
Led cross-functional effort to optimize SCE's $100 million street light business, including improving customer experience, implementing LED conversions, generating new revenue through smart cities applications, and developing a long-term strategy to achieve operational excellence; implemented various continuous improvement and Operational Excellence initiatives within Distribution

Edison Water Resources Los Angeles, CA
Vice President, Corporate Development January 2016 – January 2017
Edison International Rosemead, CA
Principal Advisor, Strategic Planning August 2015 – January 2016
Led Edison International's initial exploration of several opportunities in the water market, launched Edison Water Resources ("EWR") as a new venture within Edison International, built the water recycling business line for EWR from the ground up, began development of EWR's first water recycling projects, led M&A efforts, and ultimately recommended and managed Edison's exit from the water space

Southern California Edison Rosemead, CA
Principal Manager/Senior Manager, Energy Contracts Management January 2015 – August 2015
Managed a team responsible for all aspects of SCE's $3.7 billion portfolio of 500+ renewable, combined heat and power, qualifying facility, energy storage, conventional, gas, and resource adequacy contracts, as well as EEI, WSPP, ISDA and NAESB Master Agreements, focusing on gas fired tolling agreements and large hydro power contracts

Senior Manager, Contract Compliance & Technical Services November 2012 – December 2014
Managed a team of engineers and analysts responsible for contract compliance activities for SCE's entire contract portfolio, including contract origination, contract management, renewables portfolio standard compliance, regulatory support, site inspections, engineering consultation, resource on-boarding, CAISO markets, and database management

Contract Manager, Renewable & Alternative Power April 2010 – November 2012
Managed a complex portfolio of 40+ power purchase agreements with renewable and combined heat and power facilities totaling 2,600 MW, handling all aspects of contract administration including counterparty relationships, project onboarding, amendments, settlements, regulatory support, dispute management, and terminations

MBA Intern, Energy Efficiency June 2009 – April 2010
Analyzed operations and developed programs for the Energy Efficiency Partnerships group, making substantial, tangible contributions to more than 20 programs

EDUCATION

University of Southern California, Marshall School of Business Los Angeles, CA
Master of Business Administration, Certificate in Entrepreneurship May 2010

Tulane University, A. B. Freeman School of Business New Orleans, LA
Bachelor of Science in Management, Concentration in Finance May 2005

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mcs41@humboldt.edu

MAHAYLA SLACKERELLI

SKILLS & ABILITIES

- Entry Level North American Board of Certified Energy Professionals
- Cascadia Leadership Program Graduate
- Intermediate Spanish and Hungarian language
- Microsoft Office Suite
- PVWatts, SAM, Calpine CRM

EXPERIENCE

ACCOUNT SERVICES MANAGER, REDWOOD COAST ENERGY AUTHORITY

December 2017 - Present

- Lead account management for 62,000+ customers including billing and customer service
- Successfully implemented over 10 rate-setting cycles
- Manage net energy metering program including customer education and billing
- Developed, implemented, and manage a 6 MW Feed-in Tariff program
- Co-lead the Redwood Coast Airport Microgrid tariff development team
- Lead the Peak Day Pricing Alternative program including program design, coordinating outreach, analysis and billing

ENERGY SPECIALIST, REDWOOD COAST ENERGY AUTHORITY

August 2017 – December 2017

Analyzed data, supervised CivicSpark fellows, used the customer relationship manager to satisfy customer requests and retrieve data, liaised with student projects, represented RCEA to the public, assisted with regulatory filings and compiled meeting agendas

VICE CHAIR, ARCATA ENERGY COMMITTEE

October 2015 - Present

Review local initiatives and activities relating to energy and conservation such as transportation mode shift and county-wide climate planning and zero waste policies, communicate with the public and recommend policies to the City Council

EDUCATION

HUMBOLDT STATE UNIVERSITY – ARCATA, CA – MASTER OF SCIENCE – 2017

Energy, Technology and Policy

Thesis - Tax Equity Structures and Solar Development in Humboldt County

SARAH LAWRENCE COLLEGE – BRONXVILLE, NY – BACHELOR OF ARTS - 2009

Concentration – Economics

AWARDS

2017 Outstanding Student Research – Humboldt State University

Attachment E

SAMANTHA WEAVER

770 Francisco Street, San Francisco, CA • (313) 574-2640 • samantha.l.weaver@gmail.com

PROFESSIONAL EXPERIENCE

EAST BAY COMMUNITY ENERGY, Oakland, CA **September 2018–Present**

Principal Regulatory Analyst, Public Policy & Regulatory Affairs

Develop policy positions on behalf of EBCE and evaluate proposed policies at the CPUC, CAISO, and CEC.

- Develop analyses, written reports, and presentation materials to support EBCE's positions.
- Lead EBCE's engagement in regulatory proceedings involving distributed energy resources.

PACIFIC GAS AND ELECTRIC, San Francisco, CA **January 2015–September 2018**

Principal Case Manager, Regulatory Affairs, May 2018 – present

Regulatory case manager for the Distribution Resources Plan and Integrated Distributed Energy Resources proceedings.

- Manage compliance filings, case strategy, and development of advocacy positions.

Expert Clean Energy Policy Analyst, March 2017– present | Senior Analyst, March 2016–Feb 2017

Conduct technical and policy analysis to inform PG&E's renewable energy procurement strategy.

- Team lead for publishing PG&E's annual Renewables Portfolio Standard (RPS) Procurement Plan.

Senior Energy Policy and Planning Analyst, Energy Policy and Procurement, January 2015 – February 2016

Developed strategy and formulated policy positions related to capacity markets and distributed energy resources (DERs).

- Provide project management support for strategic initiatives focused on utility business models and DERs.

LAWRENCE BERKELEY NATIONAL LABORATORY, Berkeley, CA **January 2013–January 2015**

Senior Research Associate, Electricity Markets & Policy Group

Co-authored over ten publications and oversaw analysis of large datasets for annual renewable energy market reports.

- Played essential role in the data collection, analysis, and writing for a publication series on solar PV installed costs.
- Led data collection and analysis for a widely-cited study on the costs and benefits of RPS policies.

IHS EMERGING ENERGY RESEARCH, Cambridge, MA **May 2011–December 2012**

Senior Research Analyst, May 2012 – December 2012 | Intern May 2011 – May 2012

Published data-driven analysis in response to client questions as part of the IHS renewable energy advisory service.

- Maintained a strong understanding of the regulatory and technological landscape of the industry, with a focus on state RPS supply and demand, distributed generation, and energy storage.

DNV GL (previously DNV KEMA), Lowell, MA **June 2008– July 2010**

Data Analyst, Energy Assessments

Completed wind resource assessments and oversaw data processing to support feasibility studies for wind power projects.

- Served as the lead member of analysis team for the firm's second-largest client.

EDUCATION

Master of Arts in Urban and Environmental Policy and Planning, Tufts University, Medford, MA (2012)

- *Thesis*: Analyzed job creation potential of energy efficiency programs in Kentucky.

Bachelor of Arts in Political Science, concentration in Environmental Studies, Kalamazoo College, MI (2008)

- *Thesis with Honors*: Developed emissions inventory and carbon neutrality plan for Kalamazoo College.

SKILLS AND LEADERSHIP

Skills:

Proficiency in ArcGIS, MS Excel, Access, PowerPoint, IMPLAN; basic capabilities with R, SQL, Matlab

Leadership & Service:

Women's Network Leadership Program, Selected Participant, PG&E – San Francisco, CA June 2017-present
Board Member, Rockridge Community Planning Council – Oakland, CA, April 2014-April 2015
President Elect, Marketing and Events Director, Young Professionals in Energy – Boston, 2011-2012

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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 COMMENTS ON TRACK 3B.2 PROPOSALS

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January 15, 2021

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SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

The Energy Division Staff's findings regarding shortfalls in energy forward contracting for 2021-2024 do not justify movement from a capacity-based to an energy-based resource adequacy (RA) program design.

The Staff should exclude the Standard Fixed Price Forward Contract (SFPFC) framework for reliability and wholesale price mitigation from further consideration for numerous reasons:

- The SFPFC proposal lacks clarity after more than a year of opportunity for development.
- The proposal would not address the problem it purports to solve.
- Shifting to an entirely new reliability product will materially disrupt the market.
- The proposal imposes structural reliability risks.
- The proposal violates Public Utilities Code §380(b)(5) and §380(h)(5) by failing to "maximize" CCA's "ability to determine the generation resources used to serve their customers; this responsibility is placed in the hands of wholesale market suppliers.
- It remains unclear how the SFPFC interacts with other existing policies; in particular, it raises complex problems and questions regarding the SFPFC interface with the Commission's Integrated Resource Planning and Renewable Portfolio Standard programs and its recently adopted local RA central procurement entity framework.
- The SFPFC framework would be regulated by the Federal Energy Regulatory Commission jurisdiction or, in the alternative, Commodity Futures Trading Commission.
- The proposal unlawfully usurps the role of the CCA in managing risk.
- Simpler, more implementable solutions with fewer legal and market risks are available to address the reliability problems identified by the ED.

The California Public Utilities Commission (Commission) should proceed with further development of the structural proposal advanced by Southern California Edison Company (SCE) and the California Community Choice Association (CalCCA) to address reliability concerns.

The conceptual "slice of day" proposal advanced by Pacific Gas and Electric Company (PG&E) appears to attempt to address the same reliability problems targeted by the SCE/CalCCA proposal but leaves many questions unanswered. However, the proposal's accounting structure may provide insights for continued refinement of other proposals and it merits further discussion in a targeted workshop.

While CalCCA continues to question the Commission's authority to implement a wholesale energy market price mitigation mechanism for all load-serving entities (LSEs), there are more targeted measures that could be pursued in conjunction with the SCE/CalCCA proposal without resorting to the extreme paradigm shift embodied by the energy-based proposal.

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 TRACK 3B.2 PROPOSALS

The California Community Choice Association (CalCCA)[1] submit these Comments on Track 3.B.2 Proposals in response to the *Assigned Commissioner's Amended Track 3B and Track 4 Scoping Memo and Ruling*, dated December 11, 2020 (Scoping Ruling).

I. INTRODUCTION

The Commission instituted this rulemaking in late 2019 to consider structural reform to the existing resource adequacy (RA) program. The Scoping Memo issued on January 22, 2020, included in Track 3 "[e]xamination of broader RA capacity structure to address energy attributes and hourly capacity requirements…."[2] A year later, a handful of structural reform proposals have been offered, ranging from modifications to the existing structure to the markedly different energy-based approach advanced by Energy Division Staff. The diversity of approaches and the substantial uncertainty around resolution affect all LSEs considering long-term investments and

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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, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, 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 *Assigned Commissioner's Scoping Memo and Ruling*, Jan. 22, 2020, at 7.

procurement. LSEs are concerned that, following structural reform, resource investments made today may not be used to serve their customers following structural form, and they will face greater financial risk if the Commission shifts dramatically to a forward energy-based approach. CalCCA thus encourages the Commission to reduce this uncertainty by narrowing its focus quickly in a single direction and leaving less viable proposals on the side of the road. In making this determination, the Commission should incorporate a preference for structural reform sufficiently compatible with the current structure; this will bolster the confidence of LSEs, developers, and financiers in continuing their work developing much-needed new resources without the specter of "regulatory disqualification" or other disruption through RA reform.

CalCCA recommends removing from contention the energy-based reliability and price mitigation proposal designed by Dr. Frank Wolak and presented by Staff.[3] As Staff themselves have acknowledged, the proposal leaves important unanswered questions, not the least of which center on the foundational legal and policy issues, such as jurisdiction, compliance with state statutes governing reliability[4] (Public Utilities Code §380, and the ability to achieve the state's climate goals. Moreover, even the intricate details of the economic aspects of the proposal are challenging for stakeholders to grasp.

Other less disruptive and more implementable proposals have been advanced by stakeholders that could markedly increase reliability, particularly the proposal advanced by CalCCA and SCE in their August 7, 2020 filing.[5] While CalCCA continues to question the Commission's jurisdiction to pursue wholesale energy market price hedging as a matter of

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3 *See Administrative Law Judge's Ruling on Energy Division's Revised Track 3B.2 Proposal*, *Addendum to Energy Division Issue Paper and Draft Straw Proposal for Consideration in Track 3B.2 of Proceeding R.19-11-009* (Staff Addendum) at 13-14.

4 CAL. PUB. UTIL. CODE §380(b)(5) and (h)(5).

5 *Southern California Edison Company (U 338-E) and California Community Choice Association's Track 3 Proposal*, Aug. 7, 2020 (SCE/CalCCA Proposal).

jurisdiction, if the Commission continues to press forward, the SCE/CalCCA proposal could be combined with a simpler mechanism like the ED Staff's bid cap requirement to achieve this objective.

The Commission thus should proceed to narrow the range of options in the next two months to focus the proceeding carefully on implementation work following the May decision. After excluding the energy-based approach, other options should be further refined through workshops centered on fleshing out the details of the SCE/CalCCA proposal and further considering PG&E's "slice of day" proposal. Wholesale energy market price hedging mechanisms could be discussed along with these reliability solutions.

II. RESPONSE TO ENERGY DIVISION PROPOSALS

A. Energy Division's Analysis and Conclusions Do Not Justify the Tectonic Shift from a Capacity-Based to a Forward Energy-Based RA Framework

Staff produced supplemental analysis regarding current contracting positions in the energy and capacity markets.[6] The Staff Addendum does not, however, draw a direct connection between its analytical findings and the proposal to move to an energy-based RA framework. Indeed, while the analysis is interesting and provides useful information, it should not be viewed as the justification for an energy-based RA program design.

The ED Staff articulated findings regarding the existing forward energy contracting for 2021-2024 based on submitted LSE Individual Integrated Resource Plan Compliance Filings.[7] Staff concludes: "At an aggregate level, LSEs have only procured on average 65% of their forward energy positions for 2021-2024."[8] Undermining this conclusion, Staff, themselves,

[6] *See generally* Staff Addendum at 3-14.

[7] *Administrative Law Judge's Ruling on Energy Division's Revised Track 3B.2 Proposal*, *Addendum to Energy Division Issue Paper and Draft Straw Proposal for Consideration in Track 3B.2 of Proceeding R.19-11-009* (Staff Addendum) at 13-14.

[8] *Ibid.*

point out certain shortcomings of the aggregated analysis and overlook others. In addition, CalCCA observes that the analysis' disaggregation of positions by LSE type does paints an incomplete picture of non-IOU positions.

1. The Forward Contract Analysis Contains Uncertainties and Potential Inaccuracies and Should Not Be Used as a Foundation to Move to an Energy-Based RA Framework

The forward contract analysis, as Staff acknowledges, contains uncertainties and potential inaccuracies and, therefore, should not be used to justify a move to an energy-based RA framework. First, as Staff acknowledges, the analysis reveals the likelihood of inaccurate reporting.[9] The analysis points out that the "sum of unspecified non-imports, transfer purchases, transfer sales, and seller's choice contracts" result in a negative value.[10] Because Staff would expect unspecified non-imports[11] to have a positive value, "there is likely the misreporting of information in these values that will require further analysis and likely corrections to the data."[12]

Second, the uncertainty in the analysis is compounded by the conclusion that "a currently indeterminate portion of these contracted energy benefits are likely from solar resources so energy may not be available at the right times to meet load."[13] The analysis does not estimate this quantity nor consider whether storage will be adequate to shift energy to the appropriate periods.[14]

Third, the analysis omits a major product procured by IOUs, CCAs, and ESPs – shaped energy hedging products. LSEs of all types use hedging products to reduce exposure to energy

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9 Staff Addendum at 5-6.
10 *Id.* at 5.
11 While the analysis states that "unspecified imports" would be a positive value, context suggests Staff meant unspecified non-imports.
12 Staff Addendum at 6.
13 Staff Addendum at 7.
14 *Ibid.*

price volatility. While these resources are not appropriate for inclusion in the IRP given their indirect link to system reliability and resource planning, they are highly relevant to ED's concerns regarding market prices and LSE exposure. From the price mitigation perspective, a revised analysis including hedging products would indicate a much lower degree of open position and market price exposure on the part of LSEs.

Fourth, while not clear, the analysis may omit energy offered by RA only resources, which results in an overstatement of the reliability risk implied in the analysis. The Staff Addendum concludes that "RA Only contracts make up 32% of contracted RA, and the large majority of the RA only is attributable to thermal and unspecified resources."[15] This implies that there is potentially a significant amount of energy that will be offered into the market from these resources that is not accounted for in the total contracted energy shown in Figure 1.[16] Assuming the resource complies with its must-offer obligation (MOO), the resource owner has an obligation to offer their resources into the market such that it is available to supply customer demand. Although these resources are not subject to a fixed price or marginal cost requirements, much of this energy will be offered at the profit maximizing price. Additionally, many of these RA only contracts are with resources internal to the CAISO and they are subject to the CAISO's local market power mitigation. Ignoring the potential for additional energy from these resources thus distorts any conclusions drawn regarding energy sufficiency for 2021-2024.

Fifth, the analysis overlooks likely additional energy supplies that could brought to the market in 2021-2024. While the analysis accounts for contracted resources for this period,[17]

[15] Staff Addendum at 14.
[16] If Staff made assumptions about the likely amount of energy production from these resources, they are unstated.
[17] Staff Addendum at 3.

there may be a limited number of resources added as a result of D.19-11-016 and the most recent Summer 2021 procurement directive that are not estimated.

CalCCA agrees that RA reform is required and has offered, with SCE, a proposal to improve the existing RA program. The Staff Addendum's analysis, however, is incomplete by Staff's own admission and should not be used as a foundation for an energy-based approach to reliability.

2. The Disaggregated Forward Energy Contracting Analysis Provides an Incomplete Picture of CCA Positions

Figure 2 of the analysis overstates potential shortfalls for CCAs and Electric Service Providers of energy for this period by failing to address uncontracted energy from IOU resources in excess of IOU needs. It finds that the IOUs have long positions for energy due to the migration of customers from bundled to CCA or Direct Access service, while other LSEs are short.[18] Staff acknowledges, however, that they "are not able to determine these amounts at this time."[19] The long position, which prudent portfolio management requires to be liquidated in the market, could be substantial. In other words, CCA short positions may be filled, in part, by the IOU excess resources.

In fact, optimizing IOU excess resources through allocation has been the focus of CalCCA's efforts in R.17-06-026. As the Commission is aware, throughout 2019 CalCCA, SCE, and Commercial Energy developed a solution to address excess IOU resources and filed a final report nearly one year ago. Despite these creative solutions that go directly at the question

18 Staff Addendum at 6.
19 *Id.* at 7.

arising from the Staff's analysis, the Commission has failed to act.[20] The proposal merits the Commission's timely adoption.

B. Standard Fixed-Price Forward Contract Proposal

Staff's Addendum refines its straw proposal for a standard fixed-price forward contract (SFPFC) framework for reliability based on the market design advanced by Dr. Frank Wolak of Stanford University. The framework is effectively a mandatory, full-procurement central-buyer RA framework with an entirely new reliability product. While the proposal is an interesting academic exercise in economics, the proposal does not consider its interaction with applicable law and state policies, as the ED acknowledges. It also lacks a consciousness of the transactional dimension of the market. Consequently, it is difficult to fully understand the operation of the proposal in the current environment. Moreover, the tectonic shift the new framework promises through this new, experimental design would exacerbate the complexity and confusion in an already-uncertain RA market. Finally, despite Dr. Wolak's generous efforts to educate stakeholders, some of the details of the proposal remain elusive. For all of these reasons, CalCCA submits that the energy-based proposal cannot be implemented in a timely manner nor without substantial disruption to resource investment and the RA market.

There is little, if any, disagreement that the existing framework requires improvement to more rigorously manage reliability, but other proposals have been offered that could achieve that same objective with less complexity and disruption and a better chance of timely implementation. CalCCA urges Staff and the Commission to set the energy-based framework aside and turn limited resources and time to these more viable solutions.

[20] *See generally* R.17-06-026, *Final report of Working Group 3 Co-Chairs: Southern California Edison Company (U-338E), California Community Choice Association, and Commercial Energy*, Feb. 21, 2020.

1. The SFPFC Proposal Lacks Clarity

The ED proposal markedly shifts the reliability paradigm from a capacity product to an "energy-based" product in the form of an SFPFC commencing for compliance year 2023.[21] The mechanism would require "all electricity retailers to hold SFPFCs for energy for fractions of realized system demand at various horizons."[22] The requirement would be multi-year, requiring retail sellers to hold SFPFCs covering:

> 100 percent of realized system demand in the current year, 95 percent of realized system demand one year in advance of delivery, 90 percent two-years in advance of delivery, 87 percent three years in advance of delivery, and 85 percent four years in advance of delivery.[23]

While LSEs would be required to hold SFPFCs to cover their realized load, they would play no role in aggregating the supplies to meet their customers' requirements. The SFPFCs would be procured and allocated to LSEs by a "wholesale market operator" (WMO), which would run forward auctions for the reliability product "with oversight by the regulator."[24] The allocations of hourly energy products with parameters "set by the regulator"[25] would be based on the retail seller's share of realized demand for each month, requiring a true-up auction after realized demand for a delivery period is known.[26] In addition, the WMO would run a "clearinghouse to manage the counterparty risk associated with the counterparty," which today occurs in other wholesale markets.

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[21] Staff Addendum at 18.

[22] Staff Addendum, Appendix, *Long-Term Resource Adequacy in an Intermittent Renewable and Import Dependent Future in California,* Dec. 18, 2020 (Appendix to Staff Addendum) at 28.

[23] *Ibid.*

[24] Appendix to Staff Addendum at 29.

[25] *Id.* at 28.

[26] Appendix to Staff Addendum at 30.

Unfortunately, Dr. Wolak's proposal raises many critical questions, as ED suggested in its August 7, 2020, draft straw proposal.[27] The straw proposal offered a starting point for further assessment and development that must take place to "move in this direction," let alone implement such a proposal.[28] Neither the Staff revisions nor Dr. Wolak's revised proposal, however, make meaningful progress on these issues. Without filling in these many blanks, the Commission cannot reasonably assess the design's interaction with existing policy to justify moving the proposal forward in contention with other less complex and understandable proposals pending in this Track.

- Would the wholesale market operator be subject to FERC jurisdiction and oversight and, if so, how would the state regulator interface with the market operator?

Perhaps the most significant question arising from the proposal is the identity of the WMO regulator Dr. Wolak's references to a "wholesale" market operator suggest that the regulator would be the wholesale market regulator – today in California the FERC. Indeed, as discussed below in Section II.B.6, there is a strong likelihood that any answer other than the FERC will lead to legal conflict. It is unclear, however, whether the CAISO wants the job of market operator. Moreover, even if the state accepts FERC jurisdiction over the WMO, substantial work must be undertaken to coordinate federal jurisdiction with state goals. Key among the questions regarding placing the CAISO in this position is whether this would "jeopardize clean reliability mandates"[29] given the central focus of CAISO markets on economic efficiency.

[27] *Administrative Law Judge's Ruling on Energy Division's Track 3.B Proposal*, Aug. 7, 2020, Appendix A (Staff Straw Proposal), at 41-42.
[28] Staff Straw Proposal at 41.
[29] *Ibid.*

- ✘ The WMO's management of credit risk for the SFPFC would present significant challenges.

In a multi-year forward market, the credit requirements could be quite large and the requirements for tracking and managing the credit risk could be challenging. If, as discussed above, the WMO would be providing creditworthiness to maintain the contracts with suppliers, that implies that the WMO would require significant capitalization to ensure a robust credit rating.

- ✘ How would the SFPFC framework interface with the Commission's IRP program for individual LSEs?

The Staff Straw Proposal called out the need to determine how the SFPFC would interact with "other policy programs such as IRP and the Renewables Portfolio Standard (RPS)."[30] CalCCA shares these concerns, particularly given the risks shouldered by LSEs on behalf of their customers in meeting these requirements. Neither the Staff Addendum nor Dr. Wolak's paper does little to address these central issues.

While the IRP was briefly discussed during the January 8, 2021, workshop, CalCCA remains concerned that the proposal is incompatible with the state's mandate pursuant to Public Utilities Code §452.2(a). State law today requires *LSEs* to bear responsibility for resource development under the IRP. It appears that under Dr. Wolak's proposal, *suppliers* would be responsible for all the procurement and the IRP process would function as a backstop mechanism.[31] This would require yet another revamp of the IRP process.

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30 Staff Straw Proposal at 41.

31 Slides 19 and 37, 1/8/2021 Presentation "Long-Term Resource Adequacy in an Intermittent Renewable and Import Dependent Future in California". Dr Frank Wolak. https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Electric_Power_Procurement_and_Generation/Procurement_and_RA/RA/Track%203.B.2%20Forward%20Energy%20Workshop%20Slides.pdf

Relegating IRP to backstop function would also leave LSEs unable assemble the resource portfolio that will serve their customers. It leaves a limited role for LSEs in procurement generally, unless they or their counterparties sell the energy from their contracted resources to the WMO, only to be reallocated back through a "peanut butter" spread to all LSEs, including to the LSEs that hold the original contracts. This would mean that an LSE following a particular procurement strategy (to contract with 100 percent renewable energy for its needs, for example) would see its procurement ultimately allocated to all LSEs. Alternatively, if, as Dr. Wolak discussed, an LSE's contracted resources serve to reduce its load that it by and large already covered by SFPFCs, the LSE's customers are then exposed to over procurement costs. Thus, if the current IRP structure is maintained in concert with the SFPFC, "self-procurement" has ever more limited meaning.

Finally, it is unclear how the Commission would have visibility into the source of SFPFC commitments to determine the necessary backstop. Under the existing RA constructs, regulators (the CPUC and the CAISO) ensure that there is sufficient "iron in the ground" and can see the status of those calculations. There are questions about the calculations (how resources are counted and how much should be procured), but the calculations are visible to the regulators. Under Dr. Wolak's proposed mechanism, the WMO ensures that contracts for sufficient energy are procured, but it is not clear how the Commission would obtain visibility to the actual resources behind those contracts. If the generator who has sold an SFPFC contract to the WMO procures other generation to support the SFPFC, these contracts are likely known only to the generator and its counterparty; the WMO would not see the transaction so it would not know which generators are committed to provide the SFPFC.

CalCCA is similarly concerned about the interface of the SFPFC framework with the RPS program. CalCCA appreciates Dr. Wolak's effort to address how the state's renewable energy goals can be advanced in the energy-based framework and how the RPS program could work in concert with the proposal. During the recent workshop, Dr. Wolak suggested that "[r]enewable energy goals can be met by retailers purchasing renewable energy certificates (RECs) equal to annual demand times required renewable energy share." [32] Dr. Wolak has not fully explained, however, how LSEs could meet Bucket 1 requirements, which require that energy remain bundled with its RPS attribute. It is unclear whether his conclusion that "[p]urchase of Bucket 1 REC (energy+REC in same hour) simply implies a different hourly net load for retailer"[33] suggests that the WMO would be clearing on a "net" basis, essentially counting the resources held by the LSE, or if the LSE is left with excess costs of over-procuring energy. Moreover, the proposal lacks any detail regarding the significant complexity of ensuring, consistent with Public Utilities Code §399.13(b), that 65 percent of RPS commitments are from contracts of not less than ten years.

These questions are not trivial. Even if they could be answered, however, modifying the IRP and RPS programs around the SFPFC construct makes little sense if, as the case is, there are other simpler approaches that achieve the Commission's objectives.

- How would the SFPFC framework interface with the local RA CPE?

The Staff Straw Proposal recognized the need to harmonize changes to system reliability with the recently adopted changes in the local reliability framework.[34] Beginning in 2022, the Local RA CPE will be responsible for procuring all local RA for all LSEs.[35] It is likely that the

32 Slide 39, 1/8/2021 Presentation.
33 Slide 39, 1/8/2021 Presentation.
34 Staff Straw Proposal at 42.
35 *See generally* D.20-06-002.

CPE will procure half or more of the CPUC-jurisdictional system RA need in the course of procuring local resources.

It is unclear how, if at all, the SFPFC has contemplated its overlap with the local RA needs now the responsibility of the CPE. It is difficult to imagine maintaining a capacity-based CPE, as recently adopted, for local reliability while moving to an energy-based approach for system reliability. Local RA includes system RA, so applying two very different models to resources with both attributes seems confusing, at best. Moreover, local RA procurement – while market-based in many respects – is often driven primarily by grid engineering needs and contingency planning which are not accounted for, and perhaps incompatible with, the SFPFPC proposal.

If the two programs could not be harmonized, and the Commission were to move to the SFPFC, this would mean either scrapping the recently adopted local RA framework or leaving the program in place for only one year. The latter would make no sense since the local RA framework includes a three-year forward requirement of a capacity product. In addition, this would bring substantial dysfunction and uncertainty in the current RA markets. The Commission simply cannot move forward to further consider the SPFPC approach without answering this foundational question.

2. The SFPFC Would Not Address the Problem It Purports to Solve.

Beyond the significant open-ended issues discussed above, the SFPFC proposal fails to solve the very problem that it purports to solve. Dr. Wolak cites the "reliability externality" as a motivation for the proposal,[36] suggesting that when there are reliability shortfalls, "no retailer

[36] Appendix to Staff Addendum at 25-27.

bears the full cost of failing to procure adequate amounts of energy in advance of delivery."[37]

He continues:

> A retailer that has purchased sufficient supply in the forward market to meet its actual demand is equally likely to be randomly curtailed as another retailer of the same size that has not procured adequate energy in the forward market. For this reason, all retailers have an incentive to under-procure their expected energy needs in the forward market.[38]

Dr. Wolak's proposed structure does not eliminate this problem. Shortfalls in supply are still possible if the forward SFPFC contracting is not sufficient to cover the ultimate "realized demand" due to forecast error, generation and transmission contingencies, or suppliers' failure to deliver. In other words, the shortfalls could still occur, but without the legal and regulatory mechanisms that might be used to address the problem in the case of retail sellers under the RA program.

The proposed remedy for the shortfall will be for the procurement of energy by the suppliers in the market at high prices with the cost borne by suppliers. This is precisely the case for retailers, today, with inadequate hedging now. Suppliers will make their decisions about securing sufficient resources based on their assessment of the expected value of securing sufficient resources to meet the expected needs at the costs, versus the potential losses for being short. Especially if the energy procured is more than the expected demand, and some will be expected to be sold back after the period, suppliers may decide it is not worthwhile to procure all required energy and will plan to procure some of the excess energy that will be sold back. This would also be more likely if there is a cap on the potential costs of not having enough energy.

37 *Id.* at 25.
38 *Ibid.*

Since it is unlikely that the energy market will be completely uncapped, there will be limits on how much suppliers will be willing to spend to avoid the potential losses.

Simply shifting the responsibility for making the risk calculations on RA supply from the LSE to suppliers does nothing to "internalize" the cost of curtailment. In fact, arguably, the problem has been made worse. While LSEs may have a direct concern for reliability and the potential for curtailment of their customer loads, suppliers' behavior is limited solely to the economics of their strategy. Further, the regulator of the suppliers might have a different view of how costs, benefits and risk tradeoffs of the supply portfolio than would the regulator of the LSEs, potentially leading to different outcomes.

3. Shifting to an Entirely New Reliability Product Will Materially Disrupt the Market

The Staff Addendum would move the reliability market from today's capacity product to a new, untested, and yet undefined energy-based product. While acknowledging that this will require a transition, the Addendum underestimates the market disruption the transition will cause over a period of the next six years -- a period during which the state cannot afford more market confusion and uncertainty.

Having just adopted a massive restructuring of local RA procurement through the RA CPE proceeding, the Commission is already contemplating additional changes to the existing structure for 2022 in Track 3B.1, leaving parties very hesitant to forward contract. That uncertainty is likely to remain until the new market structure is implemented. As an example of these potential complexities, consider an LSE that has a long-term contract with a solar facility for the energy produced. In order to avoid having double procured this energy (since it will be allocated its share of the total system energy in the form of SFPFC), it appears that the energy from the solar facility will need to be bundled into an SFPFC and sold to the WMO. The LSE will either need to procure the additional energy to allow it to deliver the energy profile for the SFPFC, a complicated transaction carrying potentially large risks, or in the alternative find a generation company or marketer willing to pay for the power in order to combine it with its own resources to create a SFPFC. Especially before any of these contracts have been delivered or even before the auction has been run this seems like a daunting task with potentially large risks.

Even if the program is implemented, because new market structures (and especially new structures never implemented elsewhere) always require adjustments as lessons are learned, uncertainty will continue over the next couple of years until the rules settle. There is no certainty that this approach, in fact, would yield higher reliability than other modified capacity-based frameworks but there is certainty that it would cause market disruption on the road to implementation. Grid reliability would be best served by avoiding unnecessary significant, continuous disruptions.

As an example, consider an LSE negotiating a long-term contract for a new hybrid solar and storage facility. The LSE, developer, and financier now must contemplate a new and ill-defined set of obligations for how the energy from the project is provided through the SFPFC process, which may have dramatic and material impacts on the expected revenue stream from the facility. One interpretation suggests that the developer, or perhaps the LSE, will be obligated to bundle the energy from the hybrid facility with a firm resource – perhaps one held by a third-party merchant generator – in order for the resource to even be considered against that LSE's reliability obligations. An alternate interpretation implies that the resource could be bid directly into the SFPFC process but at greatly reduced value. The level of complexity, uncertainty, and unknown risks as these details are determined over the course of multiple years would likely significantly chill the ability of the counterparties to come to an agreement which would result in the financing and development of new resources.

4. The SFPFC Proposal Imposes Structural Reliability Risks

A central feature of "energy only" proposals, and, under CalCCA's current understanding of the SFPFC energy-based proposal, is the transition of the planning and analysis functions for capacity sufficiency from regulators and LSEs to energy suppliers. Specifically, this occurs through the shift from administratively determined capacity counting processes (RA, IRP) to market incentives for suppliers to ensure firm supply from portfolios including intermittent resources. The SFPFC proposal intends to "[let] suppliers figure out least cost way to meet system demand for energy and ancillary services" and instead limits regulatory focus to the "primary reliability problem…adequate energy to serve demand." [39] This appears to be premised on the notion that it is being implemented in a region with significant excess firm capacity that simply needs be made available to backfill the intermittency of the renewable fleet. While this may have been a reasonable (albeit untested) hypothesis when this proposal was initially submitted into the record on August 7, 2020, this premise was conclusively disproven on August 14, 2020.

While there is some ambiguity, CalCCA understands that the SFPFC proposal addresses this planning function as follows[40]:

a) Demand uncertainty may be addressed by the regulator (CPUC) increasing the forward energy purchase quantity to provide a buffer.

[39] Slide 24; 1/8/2021 Presentation.

[40] Market Design in a Zero Marginal Cost Intermittent Renewable Future Section 3.4, Mechanics of Standardized Forward Contract Procurement Process. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M344/K182/344182682.PDF

b) Intermittent resource energy is limited on an annual basis by the regulator in a manner similar to but more conservative than the Effective Load Carrying Capability (ELCC) valuation.

c) Intermittent resource capacity valuation is deferred to the market to determine capacity sufficiency.

Treatment of demand uncertainty does not depart dramatically from the current structure, in which regulators (CPUC, CEC, CAISO) determine a reasonable buffer on expected peak demand, currently the Planning Reserve Margin. CalCCA does not take issue with this approach, though notes that this is a significant departure from "energy only" markets such as the structure within ERCOT.

Treatment of renewable resource energy output on an annual basis provides unclear benefits from CalCCA's perspective. Renewable resource energy output is neither evenly nor randomly distributed but tied to more- or less-predictable daily and seasonal patterns. It is unclear how an annual energy constraint provides suppliers, LSEs, or regulators with sufficient information or incentives to make good decisions regarding renewable energy output, and seems to be simply intended to prevent renewable resources from receiving outsized revenues from SFPFCs beyond their minimum expected ability to produce.

Beyond the above structures, the proposal appears to defer the remaining renewable resource valuation and accounting questions to market forces – ensuring that hourly capacity from individual resources or resource portfolios is "firm" appears to be deferred strictly to suppliers. Specifically, the SFPFC construct asks suppliers to estimate their ability to provide firm energy with non-firm resources and sell it – with strict penalties – years in advance, and it is unclear what process, if any, would ensure unified assumptions, risk preferences, and other methodological choices are aligned between sellers beyond market forces. In effect, while the SFPFC does provide a stronger financial incentive to be able to fulfill forward commitments, fundamentally, it leaves suppliers in the same position as regulators today – grappling with uncertainty regarding future output from renewable resources. It is unclear why suppliers would have better information on future weather conditions than regulators and LSEs, or, more importantly, would make more societally beneficial determinations regarding resource need than would regulators and LSEs, which more directly face the reliability externality than do suppliers.

It is worth viewing this issue through the lens of the proposal's primary strategy for addressing hourly variability in renewable resource output – "cross-hedging" between intermittent and firm resources. Rather than administratively determining intermittent resource value, as is currently done through ELCC adjustments and other means, the proposal envisions "cross-hedging"[41] between dispatchable resources and intermittent resources as a strategy for suppliers to ensure resources are capable of meeting their hourly obligations from variable renewable resource production.

Imagine a supplier seeking to provide 100 MWh of firm hourly energy from 100 MW of wind for a September showing, as illustrated in ***Table 1***. Under the current program, a supplier would show 100 MW of wind resources, valued at 15 MW of RA capacity (15% of its nameplate value) in September, as well as 85 MW of firm resources, for a total of 100 MW of RA capacity. This could be conceptually viewed as offering 100 MWh of firm energy during the September

[41] Slide 34; 1/8/2021 Presentation "Long-Term Resource Adequacy in an Intermittent Renewable and Import Dependent Future in California". Dr Frank Wolak. https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Electric_Power_Procurement_and_Generation/Procurement_and_RA/RA/Track%203.B.2%20Forward%20Energy%20Workshop%20Slides.pdf.

peak hour, with some administratively determined risk tolerance for the wind resource producing more or less than 15 MWh.

Under the SFPFC construct (simplified as a MW obligation for illustration), the supplier's risk tolerance will dictate the degree to which it hedges a wind resource with firm resources – a risk-loving supplier might assume its wind resources will produce at its median historic energy output (50 MW]) and back its wind fleet with only 50 MW of firm capacity. In contrast, a risk-averse supplier might assume its wind resources will produce only 5% of nameplate capacity, backing its wind resources with 95 MW of firm capacity. CalCCA understands that, under the proposal, there is no provision to prevent suppliers from making either of the above decisions so long as, over the course of a year, the wind resource does not offer more than its expected annual energy output.

The alternative would require significant oversight and verification of actual generation of every resource in the state, greatly increasing the regulatory burden.

	Current RA Structure	SFPFC		
		Risk-Averse Supplier	ELCC-Based Supplier	Risk-Loving Supplier
Wind (Nameplate)	100 MW	100 MW	100 MW	100 MW
Wind (Assumed Value)	15 MW	5 MW	15 MW	50 MW
Fossil Backup	85 MW	95 MW	85 MW	50 MW
NQC Value (Current Methodology)	100 MW	110 MW	100 MW	65 MW
NQC Deficit (Current Methodology)	0 MW	-10 MW	0 MW	35 MW

Table 1: Fossil Resources Required to Firm 100MW Wind Resources in September – Comparison of Different SFPFC Supplier Approaches

In either scenario, it is true that the supplier will face economic consequences for its decisions when the wind resources are called to deliver – however, society will bear the reliability risk for the risk-loving supplier making a bad gamble. Further, unlike today, when the regulator establishes the level of reliability, the regulator will not know if those entities supplying SFPFCs are risk averse or risk-loving, so it will not fully know what level of reliability has been procured behind the forward contracts. Especially early on in such a market, before entities have experience managing these risks this seems to provide a wide range of potential outcomes including many which do not ensure system reliability.

Collectively, this results in a resource supply stack (for capacity) which is dictated not through modeling and planning, but through the individual analyses and decisions made by suppliers. While suppliers may, overall, make informed, incentive-aligned decisions, there is significant risk associated with transferring the responsibility and oversight of this system planning work from LSEs and system planners to suppliers with a wide range of risk profiles. In particular, there is risk that suppliers may not internalize the risk of high-impact, low-probability events – the exact types of risks the electric grid has traditionally planned for and which form the basis for the reliability externality.

The proposal appears to discount this risk based on two factors – one, a presumption that there is sufficient firm, physical capacity to always meet peak demand, and two, a presumption that economic incentives will rise to the level that suppliers will not want to take risks with intermittent resources, thereby pushing their assumed capacity value to zero. Although this transition to market incentives to ensure intermittent renewable resources are sufficiently firmed seems central to the proposal's "least-cost solution" to reliability in a high-renewables paradigm, paradoxically, there has also been discussion of regulatory intervention for resources which are assigned valuations which exceed their likely production, though it is unclear that this envisions expanding the annual energy constraints to an hourly accounting.[42] Further, if it is an expansion to an hourly accounting scheme, it is unclear whether this would act as a standard metric or as an

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42 Slide 19; 1/8/2021 Presentation.

enforcement mechanism for suppliers significantly overestimating production. If the former, the solution for renewable resources begins to look a lot like today's ELCC methodology – which administratively determines intermittent resource value and may over- or under-estimate actual delivered energy, but does so with an eye towards conservative assumptions which ensure reliability, breaking the proposal's efforts to reach a more least-cost system than today's structure. If the latter, it is likely that the cumulative resource valuation from suppliers will not equal the level and mix of resources which would be determined by a central procurement process, leaving uncertainty as to whether the structure truly provides for a reliable system.

5. The SFPFC Proposal's Centralized Approach Violates Public Utilities Code §380(b)(5) and §380(h)(5) by Failing to "Maximize" CCAs' Ability to "Determine the Generation Resources Used to Serve Their Customers"

The Legislature directed the Commission not once, but twice, to ensure that the resource adequacy framework secures CCA procurement autonomy. Public Utilities Code §380(b)(5)[43] requires the Commission to "establish resource adequacy requirements for all load-serving entities" in a way that will "[m]aximize the ability of community choice aggregators to determine the generation resources used to serve their customers." §380(h)(5)[44] similarly requires the Commission to "determine and authorize the most efficient and equitable means for … [e]nsuring that community choice aggregators can determine the generation resources used to serve their customers." The SFPFC proposal fails this test entirely, appearing not even to try to check this box. In addition, §380(c) requires individual LSEs to "maintain physical generating capacity and electrical demand response adequate to meet its load requirements, including, but not limited to, peak demand and planning and operating reserves."[45]

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43 CAL. PUB. UTIL. CODE §380(b)(5).
44 CAL. PUB. UTIL. CODE §380(h)(5).
45 CAL. PUB. UTIL. CODE §380(c).

As discussed above, it is unclear how the SFPFC proposal interfaces with the existing IRP and RPS frameworks, if at all. Assuming no change, LSEs could procure whatever resources they choose, but their choice would be negated by the auction structure, leaving them no influence over which resources are actually "used to serve their customers." In short, Dr. Wolak's proposal could not be adopted without a change in law.

6. FERC Jurisdiction Is Likely to Be Asserted.

It is unclear from the SFPFC proposal the roles that the CAISO and FERC would play in the framework. FERC has generally been willing to allow the Commission to establish RA capacity requirements for its LSEs within limits. California will go beyond those limits, however, if the Commission intends to regulate the "wholesale market operator" or directly or indirectly dictate wholesale energy prices.[46]

The FERC's jurisdiction arises from the Federal Power Act, which was originally enacted in 1920 and has been amended numerous times.[47] The FPA grants FERC exclusive jurisdiction over the rates, terms and conditions of wholesale sales, requiring "just and reasonable" rates,[48] prohibiting "undue preference or advantage",[49] and conferring authority to rectify any action that violates these statutory directives.[50] Consequently, Commission decisions that affect wholesale sales are likely to trigger FERC jurisdictional oversight.

FERC, on occasion, has permitted state laws and programs in several contexts where state and federal jurisdiction overlap. In fact, the Commission's program today relies on the

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46 It is also possible, given the nature of the product contemplated by the SFPFC, that the Commodity Futures Trading Commission would need to grant a waiver similar to what it did for FERC's Congestion Revenue Rights markets.

47 16 U.S.C. §§ 791, *et seq.* (the FERC was preceded by the Federal Power Commission).

48 16 U.S.C. § 824d(a).

49 16 U.S.C. § 824d(b).

50 16 U.S.C. § 824e(a).

overlap between its jurisdiction over reliability concerns and FERC's jurisdiction over wholesale sales. For example, in Order 719, FERC required regional transmission organizations and independent system operators to permit "a qualified aggregator of retail customers to bid demand response on behalf of retail customers" directly into organized, FERC regulated markets.[51] Recognizing the interface of the program with retail jurisdiction, FERC allowed states to opt out. It noted that its intent "was not to interfere with the operation of successful demand response programs, place an undue burden on state and local retail regulatory entities, or to raise new concerns regarding federal and state jurisdiction…."[52]

However, where a state law or program is so "tethered" to or directly impacts participation in the wholesale market, FERC is likely to assert jurisdiction. FERC authority under the FPA includes the exclusive jurisdiction to regulate the rates, terms and conditions of sales for resale of electric energy in interstate commerce.[53] In *FERC v. Elec. Power Supply Ass'n*,[54] the Supreme Court observed that the FPA obligates FERC to oversee "[a]ll rates and charges made, demanded, or received by any public utility for or in connection with' interstate transmissions or wholesale sales —as well as "all rules and regulations *affecting* or pertaining to such rates or charges."[55] The Court also approved a "common-sense" construction of the FPA's language which "limit[s] FERC's 'affecting' jurisdiction to rules or practices that '*directly* affect the [wholesale] rate.'"[56]

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51 *Order 719*, 125 F.E.R.C. 61071 at *459-60 (Oct. 17, 2008) (amending 18 C.F.R § 35.28).

52 *Id*. at *128.

53 *Cal. Pub. Util. Comm.*, 132 F.E.R.C. 61047, 61335 (July 15, 2010); 16 U.S.C. § 824(d) (Under the FPA, the term "sale of electric energy at wholesale" means "a sale of electric energy to any person for resale.")

54 136 S.Ct. 760 (2015).

55 *Id.* at 773 (2015) (quoting 16 U.S.C. § 824d(a))(emphasis added).

56 *Id.* at 774 (quoting *Cal. Indep. Sys. Operator Corp. v. FERC,* 372 F.3d 395, 403 (D.C. Cir. 2004)).

Caselaw establishes rough guidelines for what constitutes a "direct" impact on the wholesale market. In *Hughes v. Talen Energy Mktg., LLC.,*[57] the Supreme Court ruled that a program designed by the State of Maryland to provide subsidized price support to encourage development of new resources was preempted by federal law.[58] The program provided "subsidies, through state-mandated contracts, to a new generator, but condition[ed] receipt of those subsidies on the new generator selling capacity into a FERC-regulated wholesale auction."[59] FERC sought to preempt the program due to its effect on wholesale markets, noting the tension with state policy:

> Our intent is not to pass judgment on state and local policies and objectives with regard to the development of new capacity resources, or unreasonably interfere with those objectives. We are forced to act, however, when subsidized entry supported by one state's or locality's policies has the effect of disrupting the competitive price signals that PJM's [capacity auction] is designed to produce, and that PJM as a whole, including other states, rely on to attract sufficient capacity.[60]

The Fourth Circuit affirmed FERC's conclusion, reasoning that the program "functionally sets the rate that [generator] receives for its sales in the PJM auction," which is a FERC-approved organized market.[61] The Supreme Court agreed: "[b]y adjusting an interstate wholesale rate, Maryland's program invades FERC's regulatory turf."[62]

Just as FERC successfully asserted its jurisdiction in Maryland because of the state's direct interference in the wholesale market, it is highly likely that a similar conclusion will be reached should the Commission implement the proposed energy-only construct with the Commission at the center. Imposing the SFPFC requirement and obligating participation in the

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57 136 S.Ct. 1288 (2016).
58 *Id*. at 1290.
59 *Id*. at 1293.
60 *Id.* at 1296 (citing *PJM Interconnection,* 137 F.E.R.C. 61145, 61747 (Nov. 17, 2011)).
61 *Id*. (quoting *PPL EnergyPlus, LLC v. Nazrian*, 753 F.3d 467, 476-77 (4th Cir. 2014)).
62 *Id*. at 1297.

SFPFC auction potentially would result in a change in the mix of resources that would be developed to meet the requirement than the mix of resources that would have been developed under a different RA construct. This different mix would affect electricity market prices and thus would invite FERC jurisdiction.

Even if FERC were to decline jurisdiction over the SFPFC auction, it seems likely that the SFPFC transactions would be subject to Commodities Futures Trading Commission (CFTC) regulation over swap transactions or that a waiver from such regulation would need to be requested by the entity running the SFPFC auction. In 2010, Congress expanded the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) to broaden the scope of CFTC exclusive jurisdiction. "In particular, it expanded the Commission's exclusive jurisdiction, which had included futures traded, executed and cleared on CFTC-regulated exchanges and clearinghouses, to also cover swaps traded, executed, or cleared on CFTC-regulated exchanges or clearinghouses."[63] Without FERC oversight and a waiver from the CFTC, which the CAISO has previously obtained for its Congestion Revenue Rights market, market operation would fall to CFTC. This out-sized regulatory hurdle would need to be overcome prior to implementing the proposed SFPFC auction mechanism. Critically, however, it virtually ensures that the market operation could not be overseen by a California regulator.

A more straightforward conflict would exist if the SFPFC construct and market was only under the jurisdiction of the CPUC. The CAISO has other entities in its markets that are not subject to CPUC jurisdiction and would likely not participate in the SFPFC market. In order for those other CAISO members to use the SFPFC for RA, the CAISO would need to adopt an SFPFC RA construct and this would have to be approved by FERC. The CAISO currently has its

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[63] CFTC swap regulation Final Order, 78 Fed. Reg. 63 (April 2, 2013), citations omitted. https://www.cftc.gov/LawRegulation/FederalRegister/FinalRules/2013-07634.html

own tariff requirements for RA. These tariff requirements provide some leeway to local regulatory authorities to establish their own RA rules, but the SFPFC construct is so different from the existing CAISO tariffs that it is not apparent how LSEs or the WMO would provide the necessary RA showing to the CAISO. Companies selling SFPFCs to the WMO determine how to manage the risks through the cross-contracting, but which resources are being used for the forward energy purchases are not disclosed to the WMO, so it is unclear how the WMO would construct the resource showing required under the current CAISO tariff.

7. The Proposal Unlawfully Usurps the Role of the CCA in Managing Risk

The Commission has jurisdiction over CCAs only in very discrete areas defined by the Legislature. It certifies receipt of implementation plans,[64] certifies CCA IRP plans following approval of the CCA's governing board, [65] ensures CCAs comply with RPS requirements,[66] permits CCAs to submit proposals to satisfy their portion of renewable integration needs,[67] addresses cost shifting,[68] and is responsible for CCA compliance with RA requirements within the parameters of §380.[69] It has no jurisdiction, however, over a CCA's ratemaking or financial conditions. Contrary to this legislative framework, the Staff Addendum in large part seeks to require specific levels of energy price hedging – a financial aspect of a CCA's business that lies beyond the Commission's jurisdiction.

Apart from the jurisdictional question, requiring price hedging has much different implications for IOUs than for CCAs. The Commission regulates the energy price hedging of the

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64 CAL. PUB. UTIL. CODE §366.2(c)(7).
65 CAL. PUB. UTIL. CODE §454.52.
66 CAL. PUB. UTIL. CODE §399.15(a).
67 CAL. PUB. UTIL. CODE §454.51(d).
68 *See, e.g.,* CAL. PUB. UTIL. CODE §366.2(d), (e), and (f).
69 CAL. PUB. UTIL. CODE §380(e).

IOUs, but they have this authority only because of their obligation to ensure that IOU retail rates are just and reasonable, including the costs incurred in such hedging. CCA ratemaking, however, is squarely outside of the Commission's jurisdiction. If CCAs attempt to raise rates to cover hedging costs they risk losing customers who return to the IOUs without the benefit of a PCIA charge to ensure that those costs are recovered. In contrast, an IOU is guaranteed the costs of recovering resources procured for hedging purposes through the PCIA. The Commission cannot require a specific amount of hedging for CCAs without then ensuring – as they do with the IOUs -- that they are able to recover those costs.

8. Simpler Solutions with Fewer Legal Infirmities and Market Risks Are Available to Address the Problems Articulated by Energy Division

There are two dimensions to the SFPFC proposal: financial hedging and supply reliability. The Staff Addendum proposes the most complex, disruptive, and legally fraught approach to achieve these two ends. CalCCA recommends pursuing other proposals – chiefly, the SCE/CalCCA proposal – rather than embark on Professor Wolak's grand experiment. The SCE/CalCCA proposal, subject to refinement (much less refinement than would be required to develop and implement Professor Wolak's proposal), would achieve the Staff's identified reliability objectives.

While CalCCA has strong concerns that the proposal may not achieve its stated reliability benefits, as discussed in Section II.B.4, to the extent it does so, it likely does so in the manner least simple and least easy to implement of any of the proposals before the Commission. In contrast to the current structure, the SCE/CalCCA proposal and the newly proposed PG&E slice-of-day proposal, the SFPFC proposal does not explicitly ensure sufficient physical resources are available for CAISO to dispatch when required, and appears to rely primarily on market forces to ensure resource sufficiency. It abandons the central structures of the three aforementioned alternatives – all of which rely on an LSE-based, forward-looking obligation counted in capacity and/or energy, instead establishing a convoluted market structure which the state must hope will induce economically efficient behavior. Finally, it envisions either integrating this process into CAISO or perhaps establishing a new entity, from scratch, to operate this market in parallel to CAISO – an entity which may likely fall under FERC jurisdiction regardless. Each of these shifts would take years to envision, design, calibrate, and implement; collectively, it is hard to envision a smooth transition to this new structure in place by 2025, let alone with sufficient lead time to rectify resource shortages by then.

Similarly, if the Commission is intending to address perceived market power concerns or ensure LSE hedging – issues which are not obviously in scope for the Resource Adequacy program – the SFPFC proposal is an incredibly complex method to achieve these goals. It may also not help to address these concerns. Constructing the required hedging portfolios to support sales of SFPFC appears to be very complicated with large amounts of potential risk. It is likely that large generation or power marketing companies would have significant advantages in constructing such portfolios, both because they are of a size to manage the potential risks and because they already have a large portfolio of resources which will make it easier to assemble the required portfolio. The number of such companies is likely limited and thus the number of companies able to offer SFPFCs to the WMO would be limited and market power will remain an issue.

The following table compares the SFPFC with the SCE/CalCCA proposal, showing that the SCE/CalCCA addresses the same issues, but without the massive shift in the Resource Adequacy paradigm that would be required by the SFPFC approach.

SFPFC Element	SCE/CalCCA Track 3B.2 Proposal Element
The firm capacity values from the existing capacity-based long-term resource adequacy approach can be used to limit the amount of SFPFC energy a supplier can sell. [Appendix at 30]	Develop and apply NQC for all RA resources in a process similar to today.
The firm capacity value multiplied by number of hours in the year would be the maximum amount of SFPFC energy that the unit owner could sell in any given year… This mechanism uses the firm capacity construct to limit forward market sales of energy by individual resource owners to ensure that it is physically feasible to serve demand throughout California during all hours of the year… [Appendix at 31]	Develop NQE for all resources. Detailed methodologies to determine the NQE for various types of use-limited resources will need to be developed during implementation workshops.
SFPFCs are shaped to the hourly system demand within the delivery period of the contract. [Appendix at 28]	Develop a load curve utilizing California Energy Commission ("CEC") load forecast data on an LSE basis. The details of load forecast methodologies will be developed in consultation with the CEC, including methods for LSE data on load modifiers and local load shapes.
Expected renewable output would be addressed explicitly by limiting the amount of energy that could be sold (see Step 2).	Develop expected renewable energy from wind and solar using LSE's portfolio of resources and an energy profile for those resources from the IRP to account for expected energy from wind and solar resources.
No netting of wind and solar output.	Net the load curve with the wind and solar output.
Account for load on an hourly forecast basis.	Rank order the net load from highest to lowest to create a net load duration curve based on an hourly forecast
The advance purchase fractions of the final demand are the regulator's security blanket to ensure that system demands can be met for all hours of the year for all possible future system conditions. If the regulator is worried that not enough resources will be available in time to satisfy this requirement, it can increase the share of final demand that it purchases in each annual SFPFC auction. [Addendum at 30]	Establish the capacity (NQC) need as the highest net load hour.
See above.	Establish the energy need (NQE requirement) as the sum of the positive hourly loads for all hours. This represents the area under the net-load duration curve.
Not addressed.	Commission provides notice to LSEs of their individual allocations of Cost Allocation Mechanism and Central Procurement Entity procurement with sufficient advance notice to enable effective procurement by those LSEs. The allocations count toward the LSE's NQC and NQE compliance requirements.

SFPFC Element	SCE/CalCCA Track 3B.2 Proposal Element
These standardized fixed-price forward contracts are allocated to retailers based on their share of system demand during the month… The obligations of each retailer are then allocated to the individual hours using the same hourly system demand shares used to allocate the SFPFC energy sales of suppliers to the four hours. [Appendix at 29]	LSE shows resource portfolio to meet RA need, including dischargeable storage, dispatchable renewables, and thermal resources under RA contracts.
To the extent that there is concern that these financial incentives are insufficient for generation unit owners to address all local reliability issues, separate SFPFC products could be created for regions of the state. For example, there could separate SFPFCs for the demand nodes in Northern California and the demand nodes in Southern California. [Appendix at 33]	Local RA CPE procures sufficient local resources.
Each LSE is required to meet their share of the realized energy need.	Portfolio is assessed to see if there is sufficient energy available from the resources (including storage resources but net of energy required to charge storage) to meet the net load needs of the LSE during the hours of positive net load.
Storage is not directly accounted for, since it doesn't produce energy, but it would be an important tool for firming up intermittent resources. This mechanism ensures long- term resource adequacy in markets with retail competition while also allowing the short-term wholesale price volatility that can finance investments in storage and other load-shifting technologies necessary to manage a large share of intermittent renewable resources. [Appendix at 24]	If there is storage in the LSE portfolio, the energy need above is assessed to determine if there is excess energy necessary to fully charge the storage to deliver the necessary capacity.
A central entity would run SFPFC auctions.	The NQC and NQE obligations would be fulfilled by LSEs to meet their own load requirements via bilateral transactions.

If the Commission's goal is to mitigate market power through price controls, incremental solutions could be combined with the SCE/CalCCA proposal. This requires, however, that the Commission implement an approach that does not significantly affect the operation of the wholesale markets regulated by FERC and does not usurp a CCA's financial hedging strategies.

C. Bid Cap Requirement Proposal

The Staff Addendum proposes adoption of a price cap in RA contracts set at the "higher of $300/MWh and the resource-specific default energy bid and that these default energy bids should capture any of these gas price anomalies."[70] The ED would review bidding by RA sellers to ensure compliance. If a seller failed to comply, the LSE as buyer would be referred for non-compliance.

While the proposal would exert some level of control over the exercise of market power by suppliers, the control would be incomplete and the proposal raises three problems: jurisdiction, administrative complexity, and unintended consequences. CalCCA acknowledges, however, that if the Commission continues on its path to require a market price mitigation mechanism for the wholesale market, the Staff's proposed mechanism merits consideration.

1. The Bid Cap May Have Limited Effectiveness During Times of Constraint

The bid cap will not necessarily ensure that the prices bid by importers are at or below bid cap if the RA bids are not the marginal resources at the intertie. That is, if higher cost bids set the clearing price at the overall CAISO bid cap, then the RA imports would not face price risk for failing to perform. So there is no assurance that during times of significant constraint, when price concerns are the greatest and imports may well be the marginal resource, the cap will have its desired effect.

2. The Bid Cap May Infringe on FERC Jurisdiction

Aside from the bid cap's effectiveness, wholesale market power regulation lies within the scope of FERC jurisdiction and is currently reviewed by the CAISO's Department of Market Monitoring. This is not within the Commission's purview, as a matter of law. No doubt the Commission would argue that its price-cap regulation is a function of regulating procurement rather than wholesale market transactions. This may be a distinction without a difference in practice. As discussed in SectionII.B.6above, the question is whether the bid cap – regardless of

[70] Staff Addendum at 16.

purpose -- would have a direct impact on the operation of the wholesale market. Limiting DAM bids to $300/MWh in a FERC-regulated market with bid caps set at $2000/MWh can hardly help but have a direct impact on the price formation in that market. Thus, while some sort of bid cap on a capacity-based program may be the most viable answer to the Commission's concern, further analysis of the compatibility *overall* of the new framework with FERC jurisdiction should be considered.

3. The Bid Cap Proposal Adds Administrative Complexity

The Staff Addendum contemplates review by the ED of bids by RA counterparties into the CAISO markets. A failure of bidding within the price cap will cause the LSE buyers to be referred for RA non-compliance if "their" resources do not comply with this contractual provision.[71] This element of the proposal could be administratively burdensome, without automated tracking by CAISO. Worse yet, it places a burden on the LSE for its counterparty's non-performance. Under the current RA program, the resource owners shoulder the performance burden.

III. RESPONSE TO CAISO PROPOSALS

The CAISO advances six proposals, which largely would work within the existing capacity-based RA program structure.[72] Four of these proposals have been directed by the Administrative Law Judge to Track 3B.1.[73] CalCCA supports the remaining two recommendations under consideration in 3B.2: assessment of resources' unforced capacity (UCAP) and adoption of a multi-year system capacity requirements.

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[71] Staff Addendum at 18.

[72] *Final Track 3.B. Proposals of the California Independent System Operator Corporation*, Dec. 18, 2020 (CAISO Proposals), at i.

[73] *Email Ruling Regarding Track 3B.2 Proposals*, Jan. 11, 2021.

The CAISO proposes that the Commission's program rules reflect the same UCAP methodology the CAISO adopts in its Resource Adequacy Enhancements initiative.[74] The methodology will derive a net qualifying capacity (NQC) value by discounting a resource's deliverable QC "to account for recent historical unit forced and urgent outage rates during tight resource adequacy supply hours."[75] The Commission would work with the CAISO to set correct UCAP system requirement levels to ensure the resources procured under the Commission's program support the CAISO's reliability requirements.[76] CalCCA has supported the UCAP proposal in the CAISO stakeholder process and encourages alignment of Commission rules with this change.

The CAISO also proposes a multi-year system resource adequacy requirement for LSEs.[77] The requirement targets would be set as 100 percent for each of Years 1 and 2 and 80 percent for Year 3.[78] CalCCA does not oppose these targets in a capacity-based framework.

Finally, the CAISO concludes in its proposals that the "SCE-CalCCA proposal offers many positive elements, and the CAISO recommends the Commission and parties continue to vet, develop, and consider necessary and appropriate enhancements to the proposal for possible implementation in 2023."[79] The CAISO identifies several critical issues that need further discussion, including ensuring adequate capacity at the gross peak, the treatment of use- and availability-limited resources, and showing requirements and impacts on must-offer

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74 *Ibid.*
75 CAISO Proposals at 24.
76 *Id.* at 29.
77 *Id.* at 31.
78 *Id.* at 32.
79 CAISO Proposals at 33.

obligations.[80] CalCCA agrees that these and other issues require further consideration and looks forward to additional workshops and comments to refine the proposal.

IV. RESPONSE TO PG&E PROPOSALS

PG&E offers two proposals – one aimed to address reliability and the other market price mitigation. Although the proposal remains conceptual, PG&E's "slice of day" reliability proposal could achieve many of the same objectives pursued by the SCE/CalCCA proposal. It would not, however, escape the challenges of the market price mitigation proposal that have been identified by stakeholders. Likewise, its market price mitigation proposal bears the same infirmities as other price control proposals with added complexity.

A. "Slice of Day" Proposal

PG&E's proposal is aimed at "meeting demand in all hours of the day with resources that are able to produce during particular hours and adequately adopting RA counting methodologies that accurately measure all resource contributions for being able to meet demand in the particular hours they are being relied upon to meet demand."[81] PG&E's contemplates seasonal compliance.[82] Within each season, showings would be made for each of several hourly slices of each day; PG&E proposes slices of 11pm to 7 am, 7 am to 3 pm, and 3 pm to 11 pm.[83]

The compliance value of each resource would be what the resource is capable of delivering during that slice of day period, based on an exceedance methodology for all technologies.[84] Since solar resources would primarily produce during the second "slice" their

80 *Id.* at 34.
81 *Revised Track 3B.2. Proposals of Pacific Gas and Electric Company*, Dec. 18, 2020 (PG&E Proposals), Attachment 1 at A-3.
82 *Id.* at A-8.
83 *Id.* at A-4
84 *Id.* at A-5 – A-6.

value would be extremely limited during the third defined "slice."[85]. Storage and demand response (DR) should be able to show in any slice but charging to enable the contemplated storage discharge must be added to load in another slice. A gas-fired resource without use or availability limitations could be used for compliances in all slices of the day.

PG&E's thoughtful approach makes several key improvements on the existing system. The "slice of day proposal":

- ✓ Recognizes that time-dependent generation requires a system that accounts for reliability in all hours, and not just peak hours.
- ✓ Comes closer to technology neutrality because it recognizes that the contribution to reliability should reflect what resources are capable of delivering during each time period.
- ✓ Enables a portfolio with 100 percent renewables to be deemed adequate under this system, which is not true of the existing construct or the SFPFC proposal.
- ✓ Recognizes that load in different times of day can be met with entirely different sets of resources, unlike the MCC Bucket system, since there is no need for resources that meet load in all hours if a combination of resources can meet the same performance characteristics.

PG&E's proposal also reasonably addresses storage, recognizing that for storage to contribute to reliability, it is increasingly critical for the showing LSE to also identify the charging source for the storage. Simply relying on the market risks creating aggregate supply problems if the need for charging energy begins to exceed supply in some hours. Thus, LSEs showing storage for reliability in certain hours must identify a source for the energy to charge the storage going forward. Naturally, the power capacity used to charge storage would need to be accounted for in the RA requirements of the LSE in the hours when charging is occurring.

Despite these advances compared with today's framework, the PG&E proposal creates new issues. In general, its simplifications result in necessary imprecisions – for instance, solar

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85 *Ibid.*

resources in the early evening may be assumed to be zero while still producing, gross- and net-peak appear undifferentiated, and extrapolating peak needs across many evening hours may unnecessarily exclude resources with availability limitations (e.g. storage, demand response). While it is possible that these may be addressed with refined slice-of-day windows or a more complex accounting scheme, these refinements could shift the proposal from "slice-of-day" to "hour-of-day," negating its simplicity benefits. These issues are worth exploring further to the extent the Commission moves forward in its assessment of the proposal.

For example, the proposal fails to:

- Capture the full value of solar generation when generation, depending on what time periods the slices are actually defined;
- Resolve the complexities of reflecting hydro generation availability; and
- Provide a solution for other use- or availability-limited resources including gas-fired resources.

Address temporal mismatches that arise within each slice. For example, solar value would be driven mostly by midday generation, but at the ends of the period, solar generation will be predictably lower than the exceedance value, creating the possibility of hourly mismatch. While PG&E's slice-of-day proposal attempts to bring valuable simplicity to a complex problem, a deeper analysis illustrates that this simplicity brings with it a bluntness which may lead to over-procurement, resource mis-valuation, and other issues. For example, it is unclear that the proposal adequately differentiates between peak and net-peak load, suggesting LSEs would be obligated to procure to the full need of the evening slice (gross peak) without being able to utilize solar resources. Similarly, it is unclear whether an 8-hour evening slice would need a corresponding set of resources capable of meeting peak demand for an 8-hour period. While these periods could be refined and narrowed, this would likely result in a construct more closely resembling an hourly obligation and would lose the appeal of simplicity. Similarly, variation in load, solar, and wind production between months complicates the aggregation of months into seasons while retaining accuracy.

While CalCCA continues to believe the SCE/CalCCA proposal addresses the same issues with less complexity, PG&E's proposal merits further consideration.

B. Contract Hedge Proposal

PG&E's contract hedge proposal "ties compensation for capacity to the unit's performance in the energy market, on an ex post basis."[86] The proposal requires RA suppliers to identify variable operating costs (or a proxy) in their RA contract and require a rebate of revenues in excess of those costs to the purchasing LSE whether or not the energy is actually sold into the market. The proposal aims to ensure that RA contracted resources bid energy into CAISO market in a way that does not drive up energy prices.

CalCCA appreciates PG&E's efforts to try to address ED's pricing and risk management concerns. Again, however, the proposal presents challenges. The variable operating cost approach works for thermal resources, effectively turning the contracts into the equivalent of a tolling agreement. It is unclear, however, how these costs would be set for non-thermal resources, particularly energy storage and demand response resources. In addition, the approach fails to recognize that the bid strategy by a supplier may have many more factors than variable operating costs, such as use limitations or other factors influencing a resource's opportunity cost. For example, the proposal could result in use-limited generators being required to provide rebates to their LSE counterparties for many hours in which the market cleared above their "marginal cost," despite that quantity of hours significantly exceeding the number of hours the

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86 PG&E Proposal at A-16.

resource could actually produce over the period. In short, determining the variable operating cost on a unit-by-unit basis presents significant complexity that may weigh against the proposal's benefits.

CalCCA acknowledges the Commission's continued desire to mitigate price risk in the energy market and PG&E's attempt to respond. For this reason, PG&E's proposal should be maintained for further consideration.

V. RESPONSE TO POWEREX PROPOSALS

A. Seasonal System RA Requirement

Powerex proposes modification of the Commission's RA program to require LSEs to meet RA requirements on a seasonal basis with a showing on a year-ahead basis.[87] Powerex reasons that this approach will "ensure that California LSEs are able to more effectively compete with external LSEs to obtain forward commitments of the physical supply necessary to meet reliability needs would align California's products more closely with other markets."[88] This modification to the current framework is unnecessary and works to the benefit of suppliers, not LSEs.

Powerex argues that this approach will avoid putting California LSEs "last in line" for regional resources, will reduce forecasting errors and the need to assess when precisely the summer load will peak, and allows California to benefit from regional diversity in peak load.[89] While this approach would benefit suppliers by reducing the risk that they will be able to sell supply for all months, it is unclear how it benefits LSEs and could lead to higher costs for

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87 Powerex Comments at 2-3.
88 *Id.* at 2.
89 *Id.* at 2-3.

customers. If the only way for an LSE to obtain the supply it needs, it has the ability to contract for more than a single month; indeed, this occurs today.

B. Increased Penalties for RA Deficiencies

Powerex proposes an increase of penalties to reflect at least the full annualized Cost of New Entry.[90] CalCCA appreciates the problem Powerex aims to address: LSEs should not use non-compliance penalties as an alternative to RA compliance. Introducing an increased penalty structure, however, should not be adopted in a scarcity market *without* simultaneous adoption of a system RA penalty waiver framework that enables the Commission to better understand the reasons for non-compliance. Furthermore, increasing penalties will not result in greater reliability if the issue is a lack of supply which cannot be addressed in the short run. CalCCA continues to support adoption of a penalty waiver framework. Consequently, if the Commission intends to modify the penalties for non-compliance, a broader study should be taken to consider both the penalty level and a waiver framework.[91]

C. Assuring Imports Are Surplus to the Needs of the Source BAA

Powerex proposes a requirement for a representation that the physical generation capacity supporting an import RA contract is both surplus to the needs of the source BAA and has not been committed to any other BAA or LSE.[92] In principle, the proposal would not be objectionable if a resource owner can easily make this determination. It is not clear how a supplier, with the exception of a supplier affiliated with the balancing authority, is more likely to

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90 Powerex Comments at 4-5.

91 CalCCA offered a more detailed proposal through a Petition for Modification of D.19-06-026 and, at Staff's procedural recommendation, in Track 2 of this proceeding. *See generally California Community Choice Association's Late-Filed Track 2 Proposal*, Mar. 18, 2020.

92 Powerex Comments at 5-6.

be able to meet this requirement. Powerex's proposal thus could reduce imports from other generators who do not have the advantage of controlling their own Balancing Authority.

VI. CONCLUSION

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

Respectfully submitted,

Evelyn Kahl
General Counsel to the
California Community Choice Association

January 15, 2021

Rulemaking	20-11-003
Exhibit	____
Date	January 19, 2021
Witness	Nicholas J. Pappas
ALJ	Brian Stevens

REPLY TESTIMONY OF

NICHOLAS J. PAPPAS

ON BEHALF OF

CALIORNIA COMMUNITY CHOICE ASSOCIATION

CALCCA
ADVANCING LOCAL ENERGY CHOICE

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

REPLY TESTIMONY OF
NICHOLAS J. PAPPAS
ON BEHALF OF
CALIFORNIA COMMUNITY CHOICE ASSOCIATION

Table of Contents

I. INTRODUCTION

CalCCA appreciates the diligence and analysis that went into the testimony submitted by the wide range of stakeholders represented in this proceeding. In response to testimony submitted and its review of the documents and analysis presented, CalCCA:

- Supports immediate, tailored, "least-regrets" procurement of resources necessary to meet the need identified in Summer 2021;
- Recommends central procurement by the investor-owned utilities (IOUs) for the incremental need identified for Summer reliability in 2021, including adoption of changes to the Planning Reserve Margin, but only as necessary to enable California Independent System Operator (CAISO) backstop procurement;
- Recommends a workshop and further analysis be conducted to ensure appropriate right-sizing and allocation of procurement responsibility and cost;
- Suggests resources should be evaluated based on their feasibility, cost, term, and compatibility with state priorities; and
- Recommends action for Improved CCA Data Access.

II. CALCCA SUPPORTS IMMEDIATE PROCUREMENT ACTION

Based on the record and submitted testimony, CalCCA supports a "no regrets" approach to securing reliability for Summer 2021 despite the lack of precision regarding how much supply is truly needed. CalCCA further supports procurement of any additional supply by the IOUs in an increment above the existing resource adequacy (RA) 115 percent of peak load requirement imposed on load-serving entities for 2021.

Following the issuance of the *Final Root Cause Analysis: Mid-August 2020 Extreme Heat Wave* (Root Cause Analysis), it is clear that tightening supply margins played a key role in the August 2020 emergency reliability events. Additionally, the Root Cause Analysis identifies two other factors that led to rolling outages: an extreme heat wave and market practices that "exacerbated the supply challenges under highly stressed conditions."[1] It is worthwhile to review each of these factors in the context of policy options for Summer 2021.

First, tightening supply established the baseline risk, creating conditions for a reliability event which would not have occurred with a larger resource buffer. According to SCE's analysis, the CAISO system's actual operating reserves have declined from approximately 44% in 2011 to 14.5% in 2020[2] as resources have retired within CAISO and throughout the Western Interconnection. Further, as described in the Root Cause Analysis, the current planning metrics may overstate reliability, as they have not yet been modified to incorporate the increasing risk of extreme weather or an assessment of resource sufficiency during post peak hours. CAISO's modified stack analysis finds an expected 1,073 MW deficiency in September 2021 when considering post peak needs, and finds a 2,194 MW deficiency in September 2021 when considering both post peak needs and increased likelihood of extreme weather.[3] Both of these conclusions assume full procurement of the available resources on the CAISO 2021 Net Qualify Capacity list, as well as imports equivalent to the average procured from 2015 through 2020.

Second, the Root Cause Analysis identifies extreme weather as a key contributing factor, without which the CAISO system would have experienced lower overall demand and would likely have had access to more import resources. It is undeniable that the heat storm observed in August and September was extreme by historical planning standards – the Root Cause Analysis indicates that California experienced a 1-in-30 weather event for August and a 1-in-70 year event

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[1] California Public Utilities Commission, California Independent System Operator & California Energy Commission, *Final Root Cause Analysis: Mid-August 2020 Extreme Heat Wave,* Jan. 13, 2021 (Final Root Cause Analysis), Executive Summary at 1.

[2] Southern California Edison Company's (U 338-E) Comments on 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, November 30, 2020, at A-9.

[3] Opening Testimony of Jeff Billinton on Behalf of the California Independent System Operator Corporation, January 11, 2021 (CAISO (Billinton)), at 12.

for September.[4] These conditions go far beyond the current 1-in-2 peak weather demand RA planning standard.[5] Moving forward, it is less clear the extent to which this extreme weather is reflective of a broader climatic trend which will lead to more frequent heat storms impacting CAISO and other Western Interconnection regions. Establishing an appropriate planning standard for these events, the probability of which will likely only be fully known as events occur, is a significant policy question which will need to be informed by the best available climate predictions, as well as policymaker risk tolerances and planning preferences. A least-regrets, risk-averse approach should assume increasing likelihood of extreme weather, further stressing CAISO's narrow supply margins.

Finally, the Root Cause Analysis identifies various market practices and operational issues which exacerbated reliability concerns. CalCCA agrees with POC,[6] UCAN,[7] and TURN[8] that these practices and issues should be reviewed and, where feasible, corrected, but differs regarding the conclusion that these corrections would be sufficient to resolve reliability risk moving forward without addressing underlying supply shortages. While CalCCA shares concerns over putting ever more burden on customer rates through excess procurement, no available analysis suggests that the resources available to the CAISO system in Summer 2021 will meet the current planning standards when considering post peak operational needs.[9] While SCE provided a thorough Loss of Load Expectation study for Summer 2021 indicating a finding

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4 Final Root Cause Analysis at 40.

5 *Ibid.*

6 Prepared Opening Testimony of Bill Powers, P.E. on Behalf of the Protect Our Communities Foundation, January 11, 2021 (POC (Powers)), at 6.

7 Testimony of Samuel Golding on Behalf of The Utility Consumers' Action Network, January 11, 2021 (UCAN (Golding)), at 6.

8 Prepared Direct Testimony of Michel Peter Florio Addressing Selected Issues Regarding Electric System Reliability for 2021, The Utility Reform Network, January 11, 2021 (TURN (Florio)), at 4-5.

9 CAISO (Billinton) at 12.

that the system will very narrowly meet the load expectation (LOLE) planning standard, regrettably, this analysis included 584 MW of retired fossil resources which are no longer available to CAISO[10]. Without these resources, it is likely that SCE's revised LOLE finding would not meet the 0.1 LOLE planning standard.

In conclusion, supply shortages, extreme weather, and operating practices all contributed to the reliability events in August and September, and CalCCA supports least-regrets actions to expand available supply and address market conditions to prevent Summer 2021 reliability events. Given the significant on-going work by CAISO to address operating concerns and revise its tariff for Summer 2021, [11] a reasonable "no-regrets" policy requires attacking both supply and operating practices to give higher confidence going into Summer 2021. The Commission can best acknowledge their concerns, however, by reasonably limiting the scope of new procurement and avoiding any new, significant, long-term commitments, as well as conducting a workshop to better define the quantity of need to avoid under- or over-procurement, as discussed below.

CalCCA notes broad support among parties for immediate action to reduce potential shortages in Summer 2021. While parties differ on the magnitude of the resource need, whether it extends into 2022, and what resources are available, CalCCA notes support from CAISO,[12] PG&E,[13] SCE,[14] and SDG&E[15] for immediate action to reduce Summer 2021 reliability risks.

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[10] CalCCA (Pappas) at 10.

[11] CAISO Initiative: Market Enhancements for Summer 2021 Readiness, https://stakeholdercenter.caiso.com/StakeholderInitiatives/Market-enhancements-for-summer-2021-readiness.

[12] Opening Testimony of Dr. Karl Meeusen on Behalf of the California Independent System Operator Corporation, January 11, 2021 (CAISO (Meeusen)), at 2.

[13] Pacific Gas & Electric Company Emergency Reliability OIR Prepared Testimony, January 11, 2021 (PG&E (Clegg)), at 6-3.

[14] SCE (Walsh) at 48.

[15] Prepared Direct Testimony of San Diego Gas & Electric Company Regarding Proposals for Increasing Supply During Peak and Net Peak Demand Hours, January 11, 2021 (SDGE (Fang)), at 3.

III. CENTRAL PROCUREMENT BY IOUS IS REASONABLE IF NARROWLY TAILORED TO THESE EMERGENCY CIRCUMSTANCES

In light of the recognized need for immediate action, CalCCA proposes recommendations for Commission action in the short term. While CalCCA has made clear its preference for CAISO procurement through the CPM where possible, incremental central procurement by IOUs *apart from* the requirements of the existing RA program is a reasonable alternative in this very limited circumstance. Taking this approach will avoid the havoc and likely higher prices that would arise should numerous buyers compete against each other for limited supply if RA requirements were altered at this late date. Further, central procurement is best suited to minimizing disruption to and overlap with on-going LSE RA procurement activities.

While there are significant outstanding concerns regarding the impacts of modifying the Planning Reserve Margin for LSEs at this late date, CalCCA recognizes that some parties, including the CAISO, [16] view a modified PRM as a necessary step for CAISO to exercise its CPM authority to meet this need. To the extent that CPM is viewed as a necessary backstop to the central procurement undertaken by IOUs, a creative implementation of a revised PRM which corresponds to centralized IOU procurement and does not apply to LSE-specific compliance or penalties may be a reasonable approach for 2021.

The CAISO's approach – to apply the increased PRM to individual LSEs but not to impose penalties on LSEs failing to meet this target[17] – may be a reasonable approach to providing CAISO its desired CPM authority, but should be carefully designed for consistency with IOU procurement of the incremental need. As noted in CalCCA's opening testimony,

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[16] CAISO (Meeusen) at 2-3.
[17] CAISO (Meeusen) at 4.

separating this incremental procurement from LSE RA obligations reduces uncertainty for LSEs in the process of continuing to procure RA resources for 2021 month-ahead filings.[18]

Specifically, if, as suggested, CAISO CPM authority truly relies on a modification to the PRM, CalCCA recommends the Commission:

- Modify the PRM on a temporary basis for 2021 summer months to enable CAISO to use the CPM to remedy identified shortfalls not resolved through IOU central procurement. This modified PRM would not be applicable to individual LSEs, would not impact RA compliance obligations, and LSEs would not be subject to penalties for noncompliance penalties;

- Allocate responsibility to IOUs to procure incremental resources. The Commission should maintain the procurement responsibility at the IOU-level with costs recovered through the CAM. Resources procured under this order would be considered incremental and would not be eligible to be shown in LSE-specific RA filings.

- As noted by SDG&E, [19] the Commission should fairly allocate responsibility between IOUs to avoid unfair allocation of costs between IOU TAC areas.

- Require the IOUs to prioritize procurement based on cost, term and the ability to meet other state policies.

To avoid confusion and overlap with LSE obligations, and to ensure procurement is truly incremental to RA showings, resources procured under this process should not be allocated or shown in LSE RA showings for 2021, including IOU bundled procurement showings, though costs should be recovered through the CAM. This slightly modified CAM proposal would ensure LSEs continue to procure to their full RA obligations and avoid creating perverse incentives for LSEs to defer action until they know the allocation they will receive from this procurement.

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18 CalCCA (Pappas) at 23.

19 SDG&E (Fang) at 5.

IV. THE COMMISSION SHOULD SCHEDULE A WORKSHOP AND CONTINUE ANALYSIS TO REFINE NEED AND ALLOCATE PROCUREMENT RESPONSIBILITY APPROPRIATELY

In its opening testimony CalCCA reviewed the current record supporting procurement action.[20] While CAISO and SCE provided strong analytical contributions, CalCCA explained some limitations of the stack analysis performed as well as problematic resource assumptions utilized in the SCE stochastic loss of load study. While there is directional justification of need for immediate action, as discussed above, this analysis should be revisited to more accurately determine the quantity of procurement which should be undertaken to prepare for Summer 2021.

CalCCA reiterates that, while beginning action towards procuring to CAISO's lower estimate of 1,073 MW is a reasonable "least-regrets" strategy, further analysis is merited considering the magnitude of ratepayer expenditures involved as well as the potential that the true need is greater or lower than indicated by CAISO's analysis. CalCCA agrees with TURN[21] that an LOLE study would be a more reliable assessment and encourages the Commission to immediately schedule a stakeholder workshop to review and refine the available analyses for re-submission into the record.

V. RESOURCES SHOULD BE EVALUATED ON FEASIBILITY, COST, TERM, AND COMPATIBILITY WITH OTHER STATE POLICIES

CalCCA supports ongoing efforts to identify, where available, high feasibility, least-cost, and shortest-term projects to alleviate reliability concerns this summer, and supports giving preference to preferred resources. Both supply and demand-side procurement should be considered.

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[20] CalCCA (Pappas) at 2.

[21] TURN (Florio) at 11.

CalCCA reiterates concerns raised by PG&E[22] that permitting constraints and interconnection issues may make many supply-side options infeasible, given the short time frame available. There is apparently a very limited set of truly incremental supply-side resources capable of meeting a Summer 2021 COD. To the extent supply side options are available, CalCCA supports reviewing potential resources based on the metrics stated above. Specifically, CalCCA supports reviewing projects based on their likelihood of successfully achieving an online date that will support Summer 2021 reliability, projects which are cost-competitive, and projects which do not lock in extended payments for all ratepayers given the significant new supply which will be arriving for 2021 and 2022 as directed by D.19-11-016.

However, CalCCA believes demand-side solutions are likely the most viable options for 2021 procurement and agrees with SCE[23] that these efforts are likely to have the most immediate and meaningful impact. Thus, CalCCA encourages the Commission and IOUs to focus efforts on identifying demand-side solutions given their higher likelihood to meet the above-stated criteria.

In general, CalCCA supports utilizing competitive mechanisms, including both solicitations and bilateral negotiation, to identify cost-effective solutions. CalCCA is concerned about proposals to create new or significantly expand existing non-competitive procurement structures with significant on-going costs, such as the Emergency Load Reduction Program (ELRP) or ReMAT program proposals from the California Energy Storage Alliance (CESA) and the Green Power Institute (GPI). In particular, there is not sufficient time within this proceeding to evaluate CESA's proposal to authorize $504 million for a new 450 MW ELRP program or GPI's proposal to add 750 MW of additional capacity to the IOU ReMAT programs, both of

[22] PG&E (Clegg) at 5-2.
[23] SCE (Keating) at 2.

which would lock in hundreds of millions of dollars for many years of on-going ratepayer costs without clearly articulated corresponding benefits. For example, ReMAT contract terms, prior to the suspension of the program, were generally 10 to 20 years[24]. Similarly, CESA proposes to extend the ELRP program to five years to "support capital investments in new storage resources with project lifetimes ranging between 10 and 30 years."[25] While CalCCA sees considerable value in exploring expansion of ELRP as a "last resort" insurance policy for demand reduction which may require multi-year terms, it is unclear that ratepayer funds used to make 10 to 30 year investments in storage-backed DR, as proposed, will achieve corresponding benefits when locked in to a program designed to be used solely in emergencies and not accounted for in resource planning programs.

VI. THE IOUS SHOULD CONTINUE TO IMPROVE LSE LOAD-FORECASTING BY INCREASING DATA ACCESS

CalCCA supports UCAN's statement that SB 790 requires utilities to provide meter-specific advanced metering infrastructure (AMI) data and the assertion that CCAs should have equal access to settlement-quality AMI data for use in day-ahead forecasting.[26] UCAN is correct in stating that, while access to data does vary by CCA, not all CCAs have sufficient lead time for it to be used in their day-ahead forecasting.[27]

Further, CalCCA agrees with UCAN's statement that lack of access to AMI data serves as a barrier to dynamic rate design. Greater visibility into interval data will support CCAs'

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24 PG&E ReMAT Feed-in Tariff FAQ, https://www.pge.com/includes/docs/pdfs/b2b/energysupply/wholesaleelectricsuppliersolicitation/ReMat/ReMAT_Webpage_FAQs.pdf.

25 Opening Testimony of Jin Noh on Behalf of the California Energy Storage Alliance, January 11, 2021 at 5.

26 UCAN (Golding) at 9.

27 UCAN (Golding) at 10.

design of innovative dynamic rates that support demand flexibility.[28] Given that data accessibility varies by utility and is insufficient to meet CCAs' needs, a set standard for data quality and accessibility should be established across all IOU territories to help ensure that CCAs can offer effective dynamic rate options to their customers. To that end, CalCCA supports UCAN's recommendation to require the IOUs to offer a Service Level Agreement to provide LSE's with AMI interval data on a daily basis.[29]

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28 UCAN (Golding) at 10 –11.

29 UCAN (Golding) at 18.

Rulemaking 20-11-003
Exhibit ____
Date January 19, 2021
Witness Nicholas J. Pappas
ALJ Brian Stevens

REPLY TESTIMONY OF

NICHOLAS J. PAPPAS

ON BEHALF OF

CALIORNIA COMMUNITY CHOICE ASSOCIATION

CALCCA
ADVANCING LOCAL ENERGY CHOICE

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

REPLY TESTIMONY OF
NICHOLAS J. PAPPAS
ON BEHALF OF
CALIFORNIA COMMUNITY CHOICE ASSOCIATION

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I. INTRODUCTION

CalCCA appreciates the diligence and analysis that went into the testimony submitted by the wide range of stakeholders represented in this proceeding. In response to testimony submitted and its review of the documents and analysis presented, CalCCA:

- Supports immediate, tailored, "least-regrets" procurement of resources necessary to meet the need identified in Summer 2021;
- Recommends central procurement by the investor-owned utilities (IOUs) for the incremental need identified for Summer reliability in 2021, including adoption of changes to the Planning Reserve Margin, but only as necessary to enable California Independent System Operator (CAISO) backstop procurement;
- Recommends a workshop and further analysis be conducted to ensure appropriate right-sizing and allocation of procurement responsibility and cost;
- Suggests resources should be evaluated based on their feasibility, cost, term, and compatibility with state priorities; and
- Recommends action for Improved CCA Data Access.

II. CALCCA SUPPORTS IMMEDIATE PROCUREMENT ACTION

Based on the record and submitted testimony, CalCCA supports a "no regrets" approach to securing reliability for Summer 2021 despite the lack of precision regarding how much supply is truly needed. CalCCA further supports procurement of any additional supply by the IOUs in an increment above the existing resource adequacy (RA) 115 percent of peak load requirement imposed on load-serving entities for 2021.

Following the issuance of the *Final Root Cause Analysis: Mid-August 2020 Extreme Heat Wave* (Root Cause Analysis), it is clear that tightening supply margins played a key role in the August 2020 emergency reliability events. Additionally, the Root Cause Analysis identifies two other factors that led to rolling outages: an extreme heat wave and market practices that "exacerbated the supply challenges under highly stressed conditions."[1] It is worthwhile to review each of these factors in the context of policy options for Summer 2021.

First, tightening supply established the baseline risk, creating conditions for a reliability event which would not have occurred with a larger resource buffer. According to SCE's analysis, the CAISO system's actual operating reserves have declined from approximately 44% in 2011 to 14.5% in 2020[2] as resources have retired within CAISO and throughout the Western Interconnection. Further, as described in the Root Cause Analysis, the current planning metrics may overstate reliability, as they have not yet been modified to incorporate the increasing risk of extreme weather or an assessment of resource sufficiency during post peak hours. CAISO's modified stack analysis finds an expected 1,073 MW deficiency in September 2021 when considering post peak needs, and finds a 2,194 MW deficiency in September 2021 when considering both post peak needs and increased likelihood of extreme weather.[3] Both of these conclusions assume full procurement of the available resources on the CAISO 2021 Net Qualify Capacity list, as well as imports equivalent to the average procured from 2015 through 2020.

Second, the Root Cause Analysis identifies extreme weather as a key contributing factor, without which the CAISO system would have experienced lower overall demand and would likely have had access to more import resources. It is undeniable that the heat storm observed in August and September was extreme by historical planning standards – the Root Cause Analysis indicates that California experienced a 1-in-30 weather event for August and a 1-in-70 year event

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[1] California Public Utilities Commission, California Independent System Operator & California Energy Commission, *Final Root Cause Analysis: Mid-August 2020 Extreme Heat Wave,* Jan. 13, 2021 (Final Root Cause Analysis), Executive Summary at 1.

[2] Southern California Edison Company's (U 338-E) Comments on 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, November 30, 2020, at A-9.

[3] Opening Testimony of Jeff Billinton on Behalf of the California Independent System Operator Corporation, January 11, 2021 (CAISO (Billinton)), at 12.

for September.[4] These conditions go far beyond the current 1-in-2 peak weather demand RA planning standard.[5] Moving forward, it is less clear the extent to which this extreme weather is reflective of a broader climatic trend which will lead to more frequent heat storms impacting CAISO and other Western Interconnection regions. Establishing an appropriate planning standard for these events, the probability of which will likely only be fully known as events occur, is a significant policy question which will need to be informed by the best available climate predictions, as well as policymaker risk tolerances and planning preferences. A least-regrets, risk-averse approach should assume increasing likelihood of extreme weather, further stressing CAISO's narrow supply margins.

Finally, the Root Cause Analysis identifies various market practices and operational issues which exacerbated reliability concerns. CalCCA agrees with POC,[6] UCAN,[7] and TURN[8] that these practices and issues should be reviewed and, where feasible, corrected, but differs regarding the conclusion that these corrections would be sufficient to resolve reliability risk moving forward without addressing underlying supply shortages. While CalCCA shares concerns over putting ever more burden on customer rates through excess procurement, no available analysis suggests that the resources available to the CAISO system in Summer 2021 will meet the current planning standards when considering post peak operational needs.[9] While SCE provided a thorough Loss of Load Expectation study for Summer 2021 indicating a finding

4 Final Root Cause Analysis at 40.

5 *Ibid.*

6 Prepared Opening Testimony of Bill Powers, P.E. on Behalf of the Protect Our Communities Foundation, January 11, 2021 (POC (Powers)), at 6.

7 Testimony of Samuel Golding on Behalf of The Utility Consumers' Action Network, January 11, 2021 (UCAN (Golding)), at 6.

8 Prepared Direct Testimony of Michel Peter Florio Addressing Selected Issues Regarding Electric System Reliability for 2021, The Utility Reform Network, January 11, 2021 (TURN (Florio)), at 4-5.

9 CAISO (Billinton) at 12.

that the system will very narrowly meet the load expectation (LOLE) planning standard, regrettably, this analysis included 584 MW of retired fossil resources which are no longer available to CAISO[10]. Without these resources, it is likely that SCE's revised LOLE finding would not meet the 0.1 LOLE planning standard.

In conclusion, supply shortages, extreme weather, and operating practices all contributed to the reliability events in August and September, and CalCCA supports least-regrets actions to expand available supply and address market conditions to prevent Summer 2021 reliability events. Given the significant on-going work by CAISO to address operating concerns and revise its tariff for Summer 2021, [11] a reasonable "no-regrets" policy requires attacking both supply and operating practices to give higher confidence going into Summer 2021. The Commission can best acknowledge their concerns, however, by reasonably limiting the scope of new procurement and avoiding any new, significant, long-term commitments, as well as conducting a workshop to better define the quantity of need to avoid under- or over-procurement, as discussed below.

CalCCA notes broad support among parties for immediate action to reduce potential shortages in Summer 2021. While parties differ on the magnitude of the resource need, whether it extends into 2022, and what resources are available, CalCCA notes support from CAISO,[12] PG&E,[13] SCE,[14] and SDG&E[15] for immediate action to reduce Summer 2021 reliability risks.

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[10] CalCCA (Pappas) at 10.

[11] CAISO Initiative: Market Enhancements for Summer 2021 Readiness, https://stakeholdercenter.caiso.com/StakeholderInitiatives/Market-enhancements-for-summer-2021-readiness.

[12] Opening Testimony of Dr. Karl Meeusen on Behalf of the California Independent System Operator Corporation, January 11, 2021 (CAISO (Meeusen)), at 2.

[13] Pacific Gas & Electric Company Emergency Reliability OIR Prepared Testimony, January 11, 2021 (PG&E (Clegg)), at 6-3.

[14] SCE (Walsh) at 48.

[15] Prepared Direct Testimony of San Diego Gas & Electric Company Regarding Proposals for Increasing Supply During Peak and Net Peak Demand Hours, January 11, 2021 (SDGE (Fang)), at 3.

III. CENTRAL PROCUREMENT BY IOUS IS REASONABLE IF NARROWLY TAILORED TO THESE EMERGENCY CIRCUMSTANCES

In light of the recognized need for immediate action, CalCCA proposes recommendations for Commission action in the short term. While CalCCA has made clear its preference for CAISO procurement through the CPM where possible, incremental central procurement by IOUs *apart from* the requirements of the existing RA program is a reasonable alternative in this very limited circumstance. Taking this approach will avoid the havoc and likely higher prices that would arise should numerous buyers compete against each other for limited supply if RA requirements were altered at this late date. Further, central procurement is best suited to minimizing disruption to and overlap with on-going LSE RA procurement activities.

While there are significant outstanding concerns regarding the impacts of modifying the Planning Reserve Margin for LSEs at this late date, CalCCA recognizes that some parties, including the CAISO, [16] view a modified PRM as a necessary step for CAISO to exercise its CPM authority to meet this need. To the extent that CPM is viewed as a necessary backstop to the central procurement undertaken by IOUs, a creative implementation of a revised PRM which corresponds to centralized IOU procurement and does not apply to LSE-specific compliance or penalties may be a reasonable approach for 2021.

The CAISO's approach – to apply the increased PRM to individual LSEs but not to impose penalties on LSEs failing to meet this target[17] – may be a reasonable approach to providing CAISO its desired CPM authority, but should be carefully designed for consistency with IOU procurement of the incremental need. As noted in CalCCA's opening testimony,

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[16] CAISO (Meeusen) at 2-3.
[17] CAISO (Meeusen) at 4.

separating this incremental procurement from LSE RA obligations reduces uncertainty for LSEs in the process of continuing to procure RA resources for 2021 month-ahead filings.[18]

Specifically, if, as suggested, CAISO CPM authority truly relies on a modification to the PRM, CalCCA recommends the Commission:

- Modify the PRM on a temporary basis for 2021 summer months to enable CAISO to use the CPM to remedy identified shortfalls not resolved through IOU central procurement. This modified PRM would not be applicable to individual LSEs, would not impact RA compliance obligations, and LSEs would not be subject to penalties for noncompliance penalties;

- Allocate responsibility to IOUs to procure incremental resources. The Commission should maintain the procurement responsibility at the IOU-level with costs recovered through the CAM. Resources procured under this order would be considered incremental and would not be eligible to be shown in LSE-specific RA filings.

- As noted by SDG&E, [19] the Commission should fairly allocate responsibility between IOUs to avoid unfair allocation of costs between IOU TAC areas.

- Require the IOUs to prioritize procurement based on cost, term and the ability to meet other state policies.

To avoid confusion and overlap with LSE obligations, and to ensure procurement is truly incremental to RA showings, resources procured under this process should not be allocated or shown in LSE RA showings for 2021, including IOU bundled procurement showings, though costs should be recovered through the CAM. This slightly modified CAM proposal would ensure LSEs continue to procure to their full RA obligations and avoid creating perverse incentives for LSEs to defer action until they know the allocation they will receive from this procurement.

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[18] CalCCA (Pappas) at 23.
[19] SDG&E (Fang) at 5.

IV. THE COMMISSION SHOULD SCHEDULE A WORKSHOP AND CONTINUE ANALYSIS TO REFINE NEED AND ALLOCATE PROCUREMENT RESPONSIBILITY APPROPRIATELY

In its opening testimony CalCCA reviewed the current record supporting procurement action.[20] While CAISO and SCE provided strong analytical contributions, CalCCA explained some limitations of the stack analysis performed as well as problematic resource assumptions utilized in the SCE stochastic loss of load study. While there is directional justification of need for immediate action, as discussed above, this analysis should be revisited to more accurately determine the quantity of procurement which should be undertaken to prepare for Summer 2021.

CalCCA reiterates that, while beginning action towards procuring to CAISO's lower estimate of 1,073 MW is a reasonable "least-regrets" strategy, further analysis is merited considering the magnitude of ratepayer expenditures involved as well as the potential that the true need is greater or lower than indicated by CAISO's analysis. CalCCA agrees with TURN[21] that an LOLE study would be a more reliable assessment and encourages the Commission to immediately schedule a stakeholder workshop to review and refine the available analyses for re-submission into the record.

V. RESOURCES SHOULD BE EVALUATED ON FEASIBILITY, COST, TERM, AND COMPATIBILITY WITH OTHER STATE POLICIES

CalCCA supports ongoing efforts to identify, where available, high feasibility, least-cost, and shortest-term projects to alleviate reliability concerns this summer, and supports giving preference to preferred resources. Both supply and demand-side procurement should be considered.

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[20] CalCCA (Pappas) at 2.

[21] TURN (Florio) at 11.

CalCCA reiterates concerns raised by PG&E[22] that permitting constraints and interconnection issues may make many supply-side options infeasible, given the short time frame available. There is apparently a very limited set of truly incremental supply-side resources capable of meeting a Summer 2021 COD. To the extent supply side options are available, CalCCA supports reviewing potential resources based on the metrics stated above. Specifically, CalCCA supports reviewing projects based on their likelihood of successfully achieving an online date that will support Summer 2021 reliability, projects which are cost-competitive, and projects which do not lock in extended payments for all ratepayers given the significant new supply which will be arriving for 2021 and 2022 as directed by D.19-11-016.

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26 UCAN (Golding) at 9.

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[28] UCAN (Golding) at 10 –11.
[29] UCAN (Golding) at 18.

![California ISO]

Comments on Jan 12 Load and Export Scheduling Priorities Workshop

Initiative: Market enhancements for summer 2021 readiness

Comment period

Jan 13, 2021, 12:30 pm - Jan 20, 2021, 05:00 pm

Submitting organizations

- California Community Choice Association (CalCCA)

California Community Choice Association (CalCCA)

Submitted on 01/20/2021, 04:54 pm

Submitted on behalf of

CalCCA

Contact

Evelyn Kahl, (415) 254-5454

1. Please provide your organization's feedback on whether Residual Unit Commitment (RUC) schedules without contracted supply should continue to have a higher priority than load in real-time:

2. Provide your organization's feedback on how the ISO should clarify rules around high priority exports contracted with non-RA supply, including timing for contracting and priority relative to CAISO load:

3. Provide your organization's feedback on how the ISO should clarify rules regarding wheeling transactions:

4. Provide any additional suggestions for policy changes (implementable by June 1) needed to provide comparable treatment for ISO exports that the ISO receives for imports:

5. Additional comments:

The Idaho Power Company (IPC) presentation (
http://www.caiso.com/InitiativeDocuments/IdahoPowerPresentation-MarketEnhancements-Summer2

021Readiness-Jan122021Workshop.pdf) provided helpful background information on how BAs that are not in organized markets operate under their open access tariffs (Standard OATT BAs). Standard OATT BAs ensure resource adequacy using resources that have been procured under Integrated Resource Planning (IRP) processes in conjunction with firm and non-firm transmission service that is separately provided under their OATT. LSEs within the Standard OATT BAs must designate network resources to use firm network service for load service, and must request and be granted firm point-to-point service or secondary network transmission service (non-firm) for non-designated resources. Undesignated network resources must use point-to-point transmission service to make a firm sale to a third party.

IPC states that all load service in its BAA is backed by physical assets, either owned or contracted generation or market purchases, and market purchases are e-tagged. Energy priority is NOT tied to transmission priority and the transmission provider does not curtail transmission transactions based on energy needs of the BA. The presentation did not address the timing of the e-tagging, including whether the load service or export transactions must be tagged day-ahead or whether they can be tagged in real-time. The IPC presentation also did not make it clear whether firm transmission must be used for all load service or to support imports or exports.

The IPC day ahead group determines what physical resources are available to service load and reserve obligations and ensures there are enough physical resources to meet the obligations. If surplus resources are identified, resources are undesignated and offered for sale by the merchant to the bi-lateral market. The presentation did not state whether contracted resources or market purchases are considered in making this determination.

The IPC presentation did not address how IPC and other Standard OATT BAs treat imports into their BAA when they are making their assessments of resource sufficiency to serve their native load and exports and of available transmission for off system sales. CalCCA would like to know whether IPC and other Standard OATT BAs require that imports must use firm transmission to serve native load and exports, or whether non-firm transmission may be used. If non-firm transmission may be used, are there limitations on how much non-firm transmission may used?

The IPC presentation indicated that Third party generators within IPC that are not contracted to sell to IPC, cannot have their export schedules curtailed due to the BA being energy deficient, but their exports are subject to curtailment if the resource output does not support the schedule (but real-time outages are typically covered by contingency reserves for the first hour). Transmission curtailments are made in response to transfer capability shortages as a result of system reliability conditions. Transmission service providers do not curtail transmission service to address supply shortfalls in the BAA. CalCCA observes that the IPC BA and Standard OATT BA practices contrast with CAISO's organized market approach in a critical aspect: the CAISO runs a sequential market process (day ahead Integrated Forward Market (IFM), Hour Ahead Scheduling Process (HASP), Fifteen Minute Market (FMM) and Real-time Dispatch (RTD)). In each of these markets, the CAISO selects the lowest cost mix of resources available to serve load, given all modeled constraints. The selection process does not match specific resources with specific loads, and therefore both RA supply and Non-RA supply can get displaced by more economical resources in any step of the sequential market process. Because of this, prioritization schemes can lead to problems. For example, if self-schedules receive the highest priority, parties may be motivated to submit self-schedules to protect their priority, potentially leaving CAISO with insufficient economic bids to efficiently clear the market. Without economic bids, the models need to rely on other parameters to get the dispatch. On the other hand, if any CAISO load is to be served with economic bids, rather than self-schedules, the CAISO load could receive a lower priority than self-scheduled exports or wheel-throughs. Because exports will always be smaller than the total CAISO load (i.e., the amount transmission available for export is significantly smaller than the total CAISO load), this means that if exports are self-scheduled, there would always be at least a portion of CAISO load that would have a lower priority than exports. Absent self-scheduling all CAISO transactions, not only would CAISO load not have a higher priority than exports, at least some and potentially a very large portion of CAISO load would have a lower priority than exports. This situation does not seem tenable.

CAISO staff raised the following questions and clarifications on slide 17 of its presentation (http://www.caiso.com/InitiativeDocuments/Presentation-MarketEnhancements-Summer2021Readiness-Jan122021Workshop.pdf):

> Are additional policy changes need to provide comparable treatment for exports that CAISO receives for imports?

- Should RUC schedules without contracted supply continue have a higher priority than load in real-time?
- Clarify rules around high priority exports contracted with non-RA supply
  - Timing for contracting with non-RA supply
  - Priority relative to CAISO load when load shedding occurs
- Clarify rules regarding wheeling transactions
  - Can a wheel specify it has contracted with the import supply?
  - Must transmission be procured prior to market?

The differences in practices between Standard OATT BAs and CAISO's organized market make it very challenging to identify satisfactory responses to CAISO's questions. If CAISO is going to require that transmission be procured prior to market, what should be the appropriate term and the required timing? Hourly, daily, monthly, annual, multi-year? Post day-ahead market, pre-day-ahead market, pre-month, pre-year? How would EIM transfers be affected by these potential rules? Would EIM transfers have lower, higher, or the same priority as exports? If EIM transfers have a higher priority, would that motivate parties to favor EIM transfers over export schedules? What would be the consequences? If wheels can specify contracted supply, will internal CAISO loads need to specify their contracted supply? Will self-schedules be needed to ensure the contracted supply does not get displaced by economic bids? Will CAISO have sufficient economic bids to clear the market?

Given the number of outstanding questions and their complexity, it will be extremely challenging to develop and implement policy changes related to exports and load scheduling priorities prior to summer 2021. CAISO therefore should focus on concrete steps that parties can take to increase the resources available to the CAISO (including demand-side resources) for summer 2021. CAISO needs to ensure that raising the priority given to exports or wheels does not disadvantage service to its BAA native loads.

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

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026 (Filed June 29, 2017)

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
COMMENTS ON ASSIGNED COMMISSIONER'S AMENDED
SCOPING MEMO AND RULING**

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January 22, 2021

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**BEFORE THE PUBLIC UTILITIES COMMISSION
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**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
COMMENTS ON ASSIGNED COMMISSIONER'S AMENDED
SCOPING MEMO AND RULING**

Pursuant to the *Assigned Commissioner's Amended Scoping Memo and Ruling* filed December 16, 2020 (Amended Scoping Memo), the California Community Choice Association (CalCCA)[1] submits the following comments and answers to questions. The Amended Scoping Memo directed parties "to file responses to the questions listed in Attachment A. Comments and responses to the questions may be filed and served no later than January 22, 2021."

I. SUMMARY OF COMMENTS ON PROPOSED CHANGES TO PROCEEDING SCOPE

CalCCA supports the Amended Scoping Memo's addition of the following issues to the scope of Phase 2 of this Proceeding:

1) Should the Commission remove or modify the Power Charge Indifference Adjustment (PCIA) cap?

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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, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, 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) Should the Commission modify deadlines or requirements of Energy Resource Recovery Account (ERRA) and PCIA related submittals and reports in order to increase time for parties to review PCIA data and to facilitate timely implementation of decisions in the ERRA proceedings?

3) Should the Commission adopt a methodology for crediting or charging customers who depart from the utility service during an amortization period and who are responsible for a balance in the PCIA Undercollection Balancing Account, the Energy Resource Recovery Account, or any other bundled generation account?

4) Should the Commission consider any other changes necessary to ensure efficient implementation of PCIA issues within ERRA proceedings?[2]

Each of these issues will play an important role in ensuring the stability of the PCIA charge and fostering the ability of Community Choice Aggregators (CCAs) to have equal, transparent and timely access to the data underlying PCIA changes.

Issue 1. CalCCA supports the elimination of the PCIA cap and trigger mechanism to reduce volatility and bring greater stability in the PCIA rate. As a part of agreements with the investor-owned utilities (IOUs) in the most recent Energy Resource Recovery Account (ERRA) forecast proceedings, CalCCA anticipated supporting a petition for modification that the IOUs intended to submit to eliminate the cap and trigger mechanism. [3] The Amended Scoping Memo eliminates the need for this petition. CalCCA discusses its support for cap and trigger elimination in section II of these comments.

Issues 2 and 4: CalCCA members have previously raised concerns regarding the IOU annual ERRA submittals and process. The Scoping Ruling's addition of ERRA process and schedule issues will build on the changes the Commission adopted in recent ERRA forecast

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2 Amended Scoping Memo, at 1.

3 *See, e.g.*, D.20-12-038 at 12; D.20-12-035 at 52.

proceedings[4] and bring uniformity across the IOUs. In addition to these ERRA-specific rulings, the Commission should require the IOUs to:

- Make available to designated reviewing representatives the following:
  - Confidential versions of the monthly ERRA and Portfolio Allocation Balancing Account (PABA) reports (Monthly Reports) for each month of the year at the time such confidential versions are provided to the Commission; and
  - The same data and workpapers underlying those reports, at the same level of granularity, that are now required to be provided as part of the future ERRA forecast proceedings in each IOU service territory;
- Work with parties to this proceeding to develop non-disclosure agreements (NDAs) that are non-docket specific and specifically allow for reviewing representatives to use the data in the Monthly Reports to create PCIA rate forecasts that do not disclose confidential data and can be shared with market participants; and
- Make consistent their designation of data sets (*e.g.*, total portfolio costs) as either confidential or public across all three IOUs.

Issue 3. CalCCA agrees that crediting or charging customers who depart during an ERRA under- or overcollection amortization period must be addressed. While a common methodology has emerged over the past few years – applying charges or credits to the most recent PABA vintage, which includes both bundled and recently departed customers – the methodology has been applied inconsistently across (and even within) proceedings. Moreover, a timing problem risks misalignment of ERRA costs and cost causation: ERRA proceedings cover calendar years, while customer vintages span calendar years. Consequently, applying charges or credits accrued during a calendar year to a vintage that mixes customers who were bundled customers when the under- or over-collection accrued and departing load customers who were not risks inequitable treatment of one customer category or the other.

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4 D.20-12-035, at Ordering Paragraph (OP) 8; D.20-12-038, at OP 4; D.21-01-017, at OP 6.

II. ANSWERS TO QUESTIONS POSED IN APPENDIX A OF THE AMENDED SCOPING MEMO

A. The Power Charge Indifference Adjustment (PCIA) Cap

1. Should the Commission remove or raise the PCIA cap? Please provide rationale for your answer.

The Commission should remove the PCIA cap. The current iteration of the PCIA cap stemmed from concerns the CCAs had about a lack of transparency underlying, and the resulting inability to plan for, the large swings in the PCIA that can occur both within one year and from one year to the next. CalCCA proposed a collar on the PCIA to promote rate stability,[5] with the understanding that, if the Commission adopted certain of CalCCA's other recommendations (which were rejected), the PCIA would eventually decrease, or increase at a more sustainable rate, allowing for any revenue owed to bundled customers to be paid back in subsequent, low-PCIA years. Instead, the Commission adopted a $0.005/kWh cap proposed by direct access providers and a PCIA trigger proposal from The Utility Reform Network that was based on the existing ERRA trigger mechanism.[6]

The Commission's stated rationale for adopting a cap was to avoid PCIA volatility: "We find that the potential for volatility supports adoption of a PCIA cap in this decision. Such a cap should reduce extreme PCIA price spikes, and bill impacts, but not enable a continual state of significant undercollection.[7] Similarly, "[w]e affirm that a cap protects against volatility in the PCIA."[8] As formally set forth in Finding of Fact 18: "A PCIA cap will limit the change of the

5 D.18-10-019, at 132.
6 D.18-10-019, at 134, Finding of Fact (FOF) 19.
7 D.18-10-019, at 85.
8 D.18-10-019, at 86.

PCIA from one year to the next. A cap that limits the change of the PCIA from one year to the next promotes certainty and stability for all customers within a reasonable planning horizon."[9]

Unfortunately, the cap has failed to achieve its purpose. Rather than reducing volatility, it has increased volatility and uncertainty. To understand why volatility has increased requires delving into the details of the cap, the associated trigger, and how they have played out in practice.

Soon after adopting a cap, the Commission established balancing accounts – the PCIA Undercollection Balancing Accounts (PUBA) and Cap Balancing Account (CAPBA) -- to "track any obligation that accrues for departing load customers. . . .any balances in the account will be repaid to bundled customers with interest."[10] The cap deferred, not avoided, cost responsibility. In practical terms, unbundled customers borrow from bundled customers to finance the revenue shortfall the utility would otherwise see from application of the cap. The difference between what PCIA customers pay with a capped rate versus what they would have paid with an uncapped rate accrues in a balancing account, for unbundled customers to repay down the road.

When does repayment come due? That depends on how quickly balances build up. In the normal course, "[t]he year-end balances in the balancing accounts established pursuant to sub-paragraph (d)[sic.] above shall be incorporated into the PCIA calculation for the following year."[11] That is, if balances stay below a threshold level, and (by implication) the following year's rate is below a capped level, the prior year's balance will be recouped there. If the next year's rates are also capped, the balancing account will continue to grow. However, if the

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9 D.18-10-019, at FOF 18.

10 D.18-10-019, at 86; *see also* D.18-10-019, at OP 9(b).

11 D.18-10-019, at OP 9(c).

balance builds up to a threshold amount within a given year, then a PCIA "trigger mechanism" kicks in, and repayment obligations can arise in the same year that the cap is in effect.

The Commission adapted the PCIA trigger mechanism, and the associated thresholds, from the ERRA trigger mechanism.[12] The PCIA trigger mechanism operates as follows:

a. he PCIA trigger threshold is 10% of the forecast PCIA revenues.

b. If PG&E, SDG&E, or SCE reach 7%, and forecast that the balance will reach 10%, they shall, within 60 days, file expedited applications for approval in 60 days from the filing date when the balance reaches 7%.

c. The application shall include a projected account balance as of 60 days or more from the date of filing depending on when the balance will reach the 10% threshold.

d. The application shall propose a revised PCIA rate that will bring the projected account balance below 7% and maintain the balance below that level until January 1 of the following year.

e. If PG&E, SDG&E or SCE reach 7%, and forecast that the balance will reach 10%, they shall, within 60 days, file expedited following year, when the PCIA rate adopted in that utility's ERRA forecast proceeding will take effect.[13]

Unfortunately, the combination of the cap and trigger has exacerbated, rather than reduced, PCIA rate volatility, due in part to the erroneous assumption seen in paragraph 2 above that a PUBA balance, like an ERRA balance, can somehow self-correct.[14]

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[12] D.18-10-019, at 86.

[13] D.18-10-019, at OP 10(a), (d).

[14] A PUBA balance cannot self-correct because the rate differential between capped and uncapped PCIA rates is fixed (whereas the ERRA rate can decrease if the wholesale cost of electricity decreases). Thus, the only variable that modifies the PUBA balance is the amount of departing customer load. Thus, a PUBA balance cannot decrease, and the rate of accumulation can only slow if departed customers use less load or stop using electricity altogether.

In 2020, PG&E,[15] SCE,[16] and SDG&E[17] all reached the trigger filing threshold of 7% within a few months of 2020 PCIA rates going into effect. Each utility proposed different approaches to drawing down their respective balancing account balances, but the uniform effect was to substantially raise PCIA rates not just to, but above, the capped level (or, in an alternative formulation, to impose an adder atop PCIA rates for unbundled customers, and a credit for bundled customers). In SDG&E's case, it proposed for unbundled customers an astounding 1,438% *month-over-month* increase under one method, or a 230% month-over-month increase under an alternative method.[18]

The Commission mitigated the impacts of these proposals for 2021 by amortizing the balances over three years (rather than three months, as SDG&E proposed,[19] or a single year, as PG&E proposed), and raising the combined PCIA rate and associated surcharge to a level that avoids further balance accruals while amortizing the existing balances. Even with the Commission-approved mitigation approach, unbundled customers are seeing a substantial increase in PCIA rates from 2020 to 2021. On a system average basis, PG&E customers will see PCIA increases up to 40% with SCE and SDG&E increasing up to 55% and 39%, respectively. Moreover, in addition to payback of balances leading to a large increase in unbundled customer PCIA rates, unbundled customers in vintages prior to 2020 are also paying a systemically higher

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15 A.20-09-014, *Expedited Application of Pacific Gas and Electric Company (U 39 E) Under the Power Charge Indifference Trigger*, at 2 (September 28, 2020).

16 A.20-10-007, *Expedited Application of Southern California Edison Company (U 338 E) Regarding the Power Charge Indifference Trigger*, at 1 (October 9, 2020).

17 A.20-07-009, *Expedited Application of San Diego Gas & Electric Company (U 902 E) Under the Power Charge Indifference Adjustment Account Trigger Mechanism*, at 1-2 (July 10, 2020) (SDG&E CAPBA Trigger Application).

18 SDG&E CAPBA Trigger Application, at 6-7 (For a 3-month period, a typical residential departing load customer in the 2015 PCIA vintage using 400 kWh would have seen a monthly increase of $187 (from $13 to $200) using generation revenue allocation factors and of $30 (from $13 to $43) using an equal cents per kWh vintage rate.).

19 SDG&E CAPBA Trigger Application, at 6-7.

PCIA rate than customers in later vintages, as unbundled customers repay the above-cap amounts from 2020.

The key to reducing volatility is to stop the growth of the balances that might cause another trigger in future years while simultaneously drawing down existing balances. And that means eliminating the cap. Unless the cap is eliminated, we may well see a replay of the 2020 scenario in future years, with the added complexity of overlapping multi-year amortizations and vintaged balancing accounts. We need to get off this merry-go-round.

Considering these dynamics, CalCCA members – whose customers are the cap's ostensible beneficiaries – see the cap and trigger mechanism as an added source of uncertainty and volatility. First, because even if capped rates apply in a given year, unbundled customers have to prepare to pay back the looming balancing account balances as those balances build up. Those balances can be substantial, as demonstrated in just the few months of 2020 that gave rise to the utilities' trigger filings.[20]

Second, the deferral is brief. It would only be a one-year deferral under the "normal course" scenario set out in Decision (D.) 18-10-019, before any trigger. With a trigger, the deferral is even shorter. Under SDG&E and PG&E's trigger proposals, the cap would only have been in effect for eight months.[21] After collaborating in the short time allowed within the trigger timelines, CalCCA, its members, and the IOUs joined together in recommending that the balances be amortized over three years rather than just one, but still beginning in January 2021.

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[20] *See* D.20-12-038, at 20 ("PG&E forecasts a year-end PABA under-collection balance of $462 million for 2020, based on recorded data through September 2020 plus a forecast of the remaining three months.").

[21] SDGE's 2020 PCIA rates were effective February 1, 2020 per Advice Letter (AL) 3500-E. The utility's CAPBA proposal would have increased rates beginning in October 2020. PG&E's rates were effective May 1, 2020, per AL 5781-E. PG&E's PUBA trigger proposal would have increased rates beginning January 1, 2021.

Third, drawing down the balances raises unbundled customer PCIA rates above those of bundled customers, all else equal. This creates a competitive imbalance between IOUs and unbundled service providers.

Fourth, uncertainty around whether/when a trigger filing will occur makes rate planning more difficult.

Fifth, and finally, there is significant administrative overhead and litigation expense associated with PUBA and CAPBA trigger filings.

In recognition of these effects, CalCCA agreed with the IOUs to support an end to the cap. We continue to support ending the cap and removing the trigger mechanism and urge the Commission to do so.

2. If you think the PCIA cap should be raised, explain by how much it should be raised and provide rationale for your answer.

CalCCA does not recommend raising the cap amount. Any level of cap will present some or all of the same issues that the current cap presents. True, a higher cap (all else equal) means balances would grow more slowly than they currently do since the difference between capped and uncapped rates is reduced. But the balances will still grow, there could still be trigger filings, and the balances will still have to be repaid leading to higher PCIA rates for unbundled than bundled customers as repayment comes due (see the third point above). The Commission should prevent these dynamics by removing the cap and trigger mechanism.

3. **Would removal of the PCIA cap have an impact on Community Choice Aggregators' or Electric Service Providers' overall financial viability? Please provide a financial analysis to demonstrate the impact.**

No, for all the reasons discussed in response to question 1. In addition, the cap, after the first year of implementation, does not operate as a cap. This occurs because the trigger amount is recovered as a rider to the capped PCIA rate.[22]

4. **What principles or other factors should inform the Commission's consideration of any modifications to the cap and trigger process?**

The key principle for any modification to the cap and trigger is whether the modified cap and trigger mitigates PCIA volatility while maintaining a level playing field between bundled and unbundled customers.

5. **The investor-owned utilities must file expedited applications for approval in 60 days from the filing date when the trigger balance reaches 7% of forecast PCIA revenues.**

   a. **Should the Commission revisit the 60-day timeframe?**

CalCCA proposes to eliminate the cap and trigger mechanism and thus eliminating the need for these expedited applications. If the California Public Utility Commission (Commission) retains the mechanism, however, it should hold workshops describing how to modify the trigger application process. Most critically, any trigger mechanism should avoid same-year rate increases. As the trigger operates now, it can result in multiple PCIA increases in a year, increasing uncertainty and impairing CCA planning.

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[22] *See, e.g.,* D.20-12-035, at OP 1; D.20-12-038, at OP 6 (ordering SCE to apply a "PCIA Trigger Mechanism Surcharge" to departed load customers in addition to the capped PCIA rate).

b. Are there other modifications to the PCIA trigger mechanism that the Commission should consider, such as revisiting the PCIA trigger amount currently set to 10 percent of forecast PCIA revenues? If so, explain in detail the proposed modification and provide rationale for your answer.

CalCCA proposes to eliminate the cap and trigger mechanism, thus eliminating the need to consider trigger thresholds. If the Commission elects to retain the cap and trigger mechanism, CalCCA recommends workshops to consider this and other questions.

6. Should the PCIA cap be applied to the prior year's forecast PCIA rate, or each prior year's final PCIA rate that includes the true-up recorded actuals for energy and the Commission-issued final Resource Adequacy (RA) and Renewables Portfolio Standard (RPS) adders? Provide rationale for your answer.

CalCCA proposes to eliminate the cap and trigger mechanism and thus eliminating the need for to consider the mechanics of cap application. If the Commission elects to retain the cap and trigger mechanism, CalCCA recommends workshops to consider this and other questions.

7. Should the Commission adopt a methodology for crediting or charging customers who depart from the utility service during an amortization period and who are responsible for a balance in the PCIA Undercollection Balancing Accounts, the Energy Resource Recovery Account (ERRA), or any other bundled generation account? Explain in detail what methodology you recommend and provide rationale for your answer.

Yes, the Commission should develop and adopt a uniform methodology for addressing the application of ERRA charges or credit to bundled and departing load. To some degree, a common methodology has emerged via recent ERRA and PUBA/CAPBA trigger proceedings, but the methodology has been applied inconsistently across (and even within) proceedings and suffers from a significant short-coming resulting from a timing mismatch between ERRA forecast periods and customer vintage periods. Thus, in establishing this methodology, the Commission should consider the distortions and equities that could result from such a mismatch.

The methodology also should make certain that cost recovery or credit aligns squarely with cost causation. Lastly, the methodology should be applied uniformly across utilities and proceedings.

Before the details of this question can be considered, however, the question itself requires some clarification. It suggests that a customer departing utility service might be "responsible for a balance in the PCIA Undercollection Balancing Accounts." However, customers departing utility service can only be *owed* a PUBA balance from when they were bundled customers (*i.e.*, the customers overpaid their obligations on account of the PCIA rate cap when they were bundled customers and then departed). Departing customers would only be "responsible" for a PUBA balance if they were departed customers when a PUBA balanced accrued and then opted out to *return* to bundled service (*i.e.*, the customers underpaid their obligations on account of the PCIA rate cap when they were unbundled customers and then returned to bundled service).

With that clarification in mind, yes, the Commission should adopt a common methodology for all utilities for crediting or charging customers who depart from utility <u>or CCA</u> service during an amortization period and who are responsible for, <u>or owed</u>, a balance in the PUBA/CAPBA, the Energy Resource Recovery Account, or any other bundled generation account.

a. A Uniform Application of Methodologies to Credit or Charge Bundled and Recently Departed Customers Is Needed

Generation balancing accounts such as those for bundled ERRA rates accrue overcollections when rates are either set too high, or demand exceeds forecasted loads, over the course of a year. These overcollections represent a refund owed to customers that should be paid back to those customers. The inverse problem arises for charges to recover undercollected balances. In recent ERRA forecast and trigger proceedings, stakeholders and the Commission have coalesced around a methodology that credits (or charges) the most recent vintage in the

PABA to effectuate the refund by reducing the future generation rates customers will pay (rates would increase in the event of an undercollection). Since both bundled and unbundled customers pay the PCIA, the reduction in the PABA effectively refunds most customers that are owed a credit (and charges most customers that have underpaid).

PG&E's 2020 ERRA forecast case demonstrates this approach. In D.20-02-047, the Commission agreed with the Joint CCAs that a net ERRA overcollection must be reflected in the PCIA rate, and that the "overcollection credit should benefit all customers who paid into the overcollection."[23] The Commission ordered PG&E to "include in its Energy Resource Recovery Account Forecast application for 2021 a method to properly credit vintage 2019 and 2020 departed load customers that does not have adverse effects on PCIA vintage subaccounts."[24]

PG&E proposed returning the end-of-year ERRA balance going forward, "less the deferred revenue financed by bundled customers due to capped PCIA rate," to the 2020 vintage and that this approach be standardized for future years.[25] PG&E explained the purpose of the transfer is to "ensure that the 2020 overcollected ERRA is returned to the Vintage 2020 non-exempt departing load customer and remaining bundled customers."[26] Because customer vintages are determined on a July to June schedule, PG&E's proposal to transfer year-end ERRA balances to the most recent vintage on a going-forward basis would ensure customers departing

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23 D.20-02-047 at 11.

24 D.20-02-047 at OP 4.

25 A.20-07-002, Exh. PG&E-1 at 19-7:6-15 and 19-4:22-25. PG&E also proposed to credit a proportional share of the 2019 ERRA end-of-year balance to 2019 vintage departing load customers through a one-time PCIA rate adjustment for that vintage. A.20-07-002, *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, at 5, 12-13, 18, 21 (July 1, 2020).

26 *Id*. at 14-14:2-4.

"on or after July 1" are credited (or charged) for the ERRA balance accruing during the year of their departure.[27]

The Commission adopted PG&E's approach in D.20-12-038 but, as discussed in more detail below, did not determine it should be applied in all future years because it did not address all customers that were owed a refund.[28] Nonetheless, similar approaches have also been adopted with regard to ERRA trigger undercollections in SCE's service territory (A.18-11-009),[29] and with regard to CAPBA financing in SDG&E's service territory (A.20-07-009).[30] SDG&E's ERRA Trigger Application, A.20-12-007, also proposes a one-time transfer to PABA to address an ERRA undercollection that accrued during 2020.[31]

There are two shortcomings with this approach. First, it has been inconsistently applied to recently departed customers who, like bundled customers, financed a PUBA balance. For example, over the Joint CCAs' objections, D.20-12-038 returned PG&E's PCIA Financing Subaccount (PFS) to bundled customers via the ERRA rather than the PABA.[32] As a result, some of the funds owed to currently bundled customers who depart PG&E service during the amortization period will never receive them. Because returning an ERRA overcollection to bundled customers has the same effect as reimbursing bundled customers for having financed the

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27 A.20-07-002, Exh. JCCAs-1 at 37:20 to 38:3.

28 D.20-12-038, at 22.

29 *See* D.19-01-045, at OP 2 (stating "Southern California Edison Company shall collect the Energy Resource Recovery Account undercollection through a pro-rata apportionment of the costs to 2018 SCE bundled service customers, including 2018 and 2019 vintage departing load customers, utilizing bundled service allocation factors established in D.18-11-027, and using the Power Charge Indifference Adjustment as the rate recovery vehicle for the undercollection amount.").

30 D.20-12-028, at OP 4 (ordering "a one-time transfer of the CAPBA overcollection due to bundled customers into the 2020 vintage of its Portfolio Allocation Balancing Account").

31 A.20-09-014, *Expedited Application of San Diego Gas & Electric Company (U 902 E) Under the Energy Resource Recovery Account Trigger Mechanism*, at 2 (December 11, 2020); A.20-09-014, *Prepared Direct Testimony of Stacy Fuhrer on behalf of SDG&E*, SF-8 (December 11, 2020).

32 D.20-12-038 at 21-22.

PUBA,[33] the Joint CCAs argued it should have been 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."[34] This approach would have comported with an approach already codified in SCE's PABA implementing advice letter, which returns the PUBA balance via the PABA, ensuring customers that are owed a refund would receive one.[35]

The PG&E decision did not, and could not, explain why those purported differences warrant such an inequitable outcome. The decision states only that "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."[36] That is, the decision promoted PG&E's preferred accounting treatment over providing full refunds to ratepayers that paid into a balance they were owed. However, the Commission did state it "may consider structural changes to the [PFS] when we address PCIA framework issues in the appropriate proceeding."[37] The Commission should address such revisions as part of this proceeding.

More broadly, recent decisions establishing three-year amortization periods for the PUBA balances for PG&E and SCE and the CAPBA for SDG&E did not address customer

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33 A.20-07-002, Exh. JCCAs-1 at 41:11-13.

34 D.20-02-047, at 11.

35 SCE AL 4084-E and SCE Preliminary Statement Section Q.3.b (stating "The year-end balance in this subaccount is returned, in its entirety with interest, through a transfer to the applicable vintage subaccount of the PABA.").

36 D.20-12-038 at 21-22.

37 D.20-12-038 at 21-22.

crediting for years other than 2021.[38] Thus, a crediting methodology must still be developed (and uniformly implemented) for 2022 and 2023.

CalCCA supports the approach that has emerged over recent years, which most closely aligns cost responsibility with cost causation, but it must be applied uniformly. Transferring the amount due customers who were bundled customers at the time the cost was incurred to the recent PABA vintage(s) ensures that all customers – bundled or recently departed – receive credit for their share of an ERRA overcollection or PUBA/CAPBA balance they helped finance. This approach aligns with long-standing ratemaking principles, is simple to implement, and will produce a uniform approach for balancing account under collections across all utilities.

b. The Problem Is Complicated by the Mismatch Between the Vintaging Methodology and Ratemaking Calendar

The second shortcoming with the current approach is that customers that depart in the first half of a year in which an overcollection accrues are unlikely to receive any credit for refunds they are owed (with the inverse being true in the case of an undercollection). This issue stems from the fact that vintages are set with a mid-year cutoff, while PCIA and ERRA rates are (generally) set on a calendar year basis. A hypothetical overpayment through, say calendar year 2019, if refunded to *vintage* 2019 will be underinclusive. Why? Because the vintaging rules' June cut-off means *vintage* 2019 does *not* include customers who departed January through June 2019. Those customers are vintage 2018. So even though they left IOU service in 2019 and

[38] D.20-12-028, at OP 4, at 22 (SDG&E) ("We recognize the importance of approving a consistent method for returning balances to customers but will not adopt PG&E's going-forward proposal at this time. We will consider a long-term solution when we address PCIA framework issues in the appropriate proceeding."); *id.* at 9 ("In this decision we do not rule on SDG&E's argument, made in its reply briefs, that the Commission should require departing customers leaving SDG&E in the middle of 2021 to forgo a refund, though we do approve a one-time transfer of the CAPBA overcollection due to bundled customers into the 2020 vintage of PABA."); *see* D.20-12-035, at OP 6 (SCE); *see also* D.20-12-038, at 18, OP 1 (PG&E).

would have contributed to the amount being refunded, they would not see a refund. While you could pick those customers up by refunding to the 2018 vintage, now you would be overinclusive, since some of the 2018 vintage customers would in fact have left in calendar 2018, and not contributed to the amount being refunded.

This quandary was considered in the PG&E 2021 ERRA forecast case above, where customers receiving a credit were those who departed on or after July 1, 2020 (or remained bundled PG&E customers) and paid into ERRA for at least the first half of 2020.[39] However, customers that overpaid in 2020, but left during the first half of 2020, would not receive a refund to which they are entitled when the most recent vintage (in this case, 2020) is credited via PABA because those customers are 2019 vintage customers. Stated another way, the refund misses "half" the vintage.

It was for this reason the Commission did not formally adopt PG&E's approach of crediting the most-recent vintage on a going-forward basis.[40] As part of this expanded proceeding, the Commission should explore how to resolve this problem consistently and equitably, by revising the vintaging rules, modifying the ratemaking calendar, or another approach.

B. Improving PCIA and ERRA Alignment

1. How should the Commission modify the deadlines and requirements of ERRA and PCIA-related submittals and reports in order to increase time for parties to review PCIA data while facilitating an ERRA implementation on January 1 of each year? Explain in detail the proposed modification and provide rationale for your answer.

The CCAs have repeatedly requested opportunities to revise the annual ERRA process, and resulting Annual Electric True-Up (AET), to ensure both stakeholders and the Commission

39 A.20-07-002, Exh. JCCAs-1, Attachment B, PG&E's response to Joint CCA DR 3.34.
40 D.20-12-038, at 22.

have sufficient time to adequately analyze the complex and high-stake issues in an ERRA proceeding, while also acknowledging the need to litigate the proceeding on an expedited timeline. In 2019, the CCA parties to PG&E's ERRA Forecast proceeding sought "Commission guidance for a forum in which more concrete procedural mechanisms might be adopted for all IOU ERRA processes."[41] CalCCA appreciates the Assigned Commissioner's response by amended the Scoping Ruling for this phase.

Thematically, the challenges parties (and, by extension, the Commission, where it relies on parties for record development) face break down into two categories:

(1) Challenges accomplishing needed work given unusually short deadlines, and

(2) Challenges obtaining needed information from utilities (which then exacerbate problem (1)).

The Joint CCAs laid these challenges out graphically back in 2019. Harking back to the experience of 2018, Joint CCAs stated:

> Addressing the November Update was a difficult task—an exercise in legal triage that barely maintained due process thanks to an extraordinary ALJ ruling and the unusual but necessary step of requiring a Tier 2 Advice letter to implement an ERRA forecast decision. It required analyzing 80 pages of updated testimony, scrutinizing 13 sets of workpapers, participating in two informal workshops, submitting and reviewing responses from two sets of discovery totaling 29 data requests (excluding tens of additional sub-parts), drafting 35 pages of comments, and submitting a Motion to add 15 exhibits to the record. The parties had ***<u>10 days</u>*** to accomplish all of these tasks, which turned into 12 days given the timing of the update resulted in a Saturday deadline.[42]

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[41] A.19-06-001, *Protest of the Joint CCAs to the Application of Pacific Gas and Electric Company (U 39 E) for 2020 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast And Greenhouse Gas Forecast Revenue Return And Reconciliation*, at 28 (July 5, 2019) (referencing, A.18-06-001, *Assigned Commissioner's Scoping Memo And Ruling*, at 4 (Aug. 16, 2018)).

[42] *Id.* at 30.

It is incumbent upon CCAs to assist the millions of unbundled customers in California in planning for rate changes in the ERRA that, in the past, have led to significant, volatile and near-term changes in customers' monthly electricity bills. The opacity of IOU filings, and the Commission's ERRA framework in general, have repeatedly and consistently frustrated CCAs' efforts to advocate for their customers.

a. Master Data Requests and More Detailed and Timely Workpapers Are Necessary to Ensure Full and Fair Data Access by Customers Paying the PCIA

In each of its recent ERRA forecast decisions, the Commission took strides toward leveling the playing field within those proceedings and increasing LSEs' ability to predict and plan for PCIA rate changes that primarily rely on confidential, utility-specific cost and revenue data. For example, in D.20-12-035, the Commission found that "[c]ertain market participants, including CCAs, require timely access to SCE's ERRA/PABA/PUBA reporting as well as precise volume of RA, RPS and other metrics in order to meet their evidentiary burden in the ERRA forecast proceeding."[43] It further determined that delaying access to the "ERRA/PABA/PUBA and other reports concerning the validity of SCE's ERRA forecast application until the November Update, and requiring extensive discovery requests to obtain this information, creates additional administrative burdens for the parties to the proceeding as well as Commission staff."[44]

The Commission required SCE to "provide the following information in Energy Resource Recovery Account (ERRA) forecast proceeding workpapers and monthly ERRA compliance reports, starting January 2021:

(a) Confidential version of monthly ERRA/PABA/PUBA activity reports;

43 D.20-12-035, FOF 38.
44 D.20-12-035 at 56.

(b) Additional detail supporting the monthly PABA reports, including subcategories for summarized line items such as utility-owed generation (UOG) costs and contracts (*e.g.*, provide by resource type, and whether Renewables Portfolio Standard (RPS) or non-RPS eligible);

(c) Actual or accrued 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 accrued volumes of Actual Sold, Retained, and Unsold Resource Adequacy capacity; and

(e) Monthly accrued volumes of Actual Sold, Retained, and Unsold RPS-eligible energy.[45]

The Commission made nearly identical findings and orders in both PG&E and SDG&E's ERRA Forecast decisions, requiring a Master Data Request in the PG&E case.[46] The Commission also specified in that case the following process: "After PG&E has filed an ERRA forecast application, and so long as such application is pending, PG&E will provide the specified information to reviewing representatives that have signed a nondisclosure agreement within 5 days after it submits each monthly ERRA/PABA/PUBA activity report to the Commission."[47] Requiring the data in the SCE case be provided, and this PG&E process to be followed, by all IOUs in their respective ERRA Filings will ensure uniformity in CCAs' access to data and significantly improve transparency in these expedited and opaque proceedings.

b. Equal, Transparent and Timely Access to Data are Necessary During all 12 Months of the Year.

The ability of CCAs to have equal, transparent and timely access to the data underlying changes to the PCIA has been a consistent point of contention for many years. Under the Commission's indifference framework, the PABA and the PCIA are inextricably linked to IOU

45 D.20-12-035 at OP 8.
46 D.20-12-038, 31-32 and OP 4; D.21-01-017 at OP 6.
47 D.20-12-038, 31-32, Conclusion of Law 11, and OP 4.

data the CCAs currently cannot access on a periodic basis outside of an active ERRA proceeding. This prohibition even applies to the CCAs' reviewing representatives under D.06-06-066 and the Commission's confidentiality framework. Those data include foundational data such as actual retail customer sales, which can significantly impact the PABA due to typical factors like weather and atypical factors like the COVID-19 pandemic and the IOUs' Public Safety Power Shut-off events.

As D.20-12-038 recognizes, each utility "already provides certain data regarding its ERRA/PABA/PUBA balances and other metrics associated with its ERRA forecast to the Commission on a monthly basis."[48] However, the monthly reports do not include volumetric data, which is necessary to understand why the PCIA is moving the way it is moving and to predict where the PCIA may head in the future based on different scenarios.

Thus, while the actions the Commission took to increase transparency in the ERRA Forecast proceedings will be helpful, year-round access to key cost and revenue data for the CCAs' designated reviewing representatives is the next critical step. Only year-round access to data achieves a level playing field in LSEs' ability to plan for PCIA rate changes and accurately forecast which direction those changes will go. As D.20-12-038 recognizes, "[g]ranting independent consultants access to confidential market sensitive information, under appropriate non-disclosure agreements, is a reasonable means of allowing market participants to review confidential versions of ERRA/PABA/PUBA reports."[49]

For this reason, the Commission should require the IOUs to make available to designated reviewing representatives the following:

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[48] D.20-12-035, Conclusion of Law 39.

[49] D.20-12-035, OP 5.

- Confidential versions of the Monthly Reports for each month of the year at the time such confidential versions are provided to the Commission; and
- The same data and workpapers underlying those reports, at the same level of granularity, and within the same schedule, that is now required to be provided as part of future ERRA forecast proceedings in each IOU service territory.

In light of the fact that much of the information contained in these reports is confidential, it would be appropriate for the Commission also require the IOUs work with parties to this proceeding to develop NDAs that are non-docket specific, *i.e.*, NDAs that would apply to year-round provision of confidential data. The NDAs should also specifically allow for reviewing representatives to use the data provided in the Monthly Reports outside the context ERRA Forecast proceedings for the limited purpose of creating PCIA rate forecasts that are based on, but do not disclose, confidential data, and can be shared with CCA decision-makers to allow them to plan for future rate changes.

c. Discovery Timelines Should Be Tightened

Subject to the caveat that parties reasonably limit the number of requests, CalCCA suggests the following discovery timelines:

- Between the Application Date and Rebuttal Testimony – 10 Business Days (BDs)
- Between Intervenor Testimony and IOU Rebuttal Testimony – 5 BDs
- Between IOU Rebuttal Testimony and Hearings – 3 BDs
- Between final Update and Comments to final Update (or Intervenor Updated Testimony) – 2 BDs

In addition, parties should be required to serve workpapers concurrently with testimony and any updated or supplemental testimony in each ERRA forecast proceeding, and all workpapers should have (a) formulas intact, (b) underlying data included, and (c) avoid the use of hard-coded data that have little value.

d. A Modified Schedule Is Required to Reduce the Year-End Chaos Arising from November Updates

The Scoping Ruling rightly identifies the need to consider modifications of the current ERRA forecast requirements and schedules to bring greater transparency and efficiency to the process. While CalCCA is still considering the details of a modified schedule, certain issues warrant initial consideration. Most critical to CalCCA is ensuring the use of most current possible pricing data for market price benchmarks in ERRA forecast proceedings. Depending upon the broader direction of any changes, schedule modifications could include the following:

- ✓ Advance the submittal date for the November Update by one week.
- ✓ Following the November Update, set the following intervals for submittals:
    - o Comments on the November Update would be due between 12 and 15 days after its submittal, depending on how calendar plays out;
    - o Parties would be required to use their best efforts to respond to data requests within 3 business days;
    - o Comments on a proposed decision (PD) would be due between 7 and 10 days before meeting date at which the decision will be adopted;
    - o Reply comments on the PD would be due three days before the adoption meeting.

Finally, the Commission should consider the timing of PG&E's Annual Electric True-Up advice letter to avoid year-end confusion.

Optimally, however, schedule issues should be explored collectively among stakeholders, Key questions to explore include the following:

- Whether/how to constrain the final update in ERRA forecast proceedings to "turn of the crank" type changes (e.g., MPB updates), and avoid the surprises and litigation seen in the past several ERRA forecast proceedings;
- How to stagger IOU filings to reduce overlapping deadlines for staff common to multiple IOU ERRA proceedings;

- Whether to push the implementation date for new rates from January 1, 2021 to a later date; and

- Whether to push back the annual electric true-up filing for PG&E.

CalCCA recommends a workshop to explore these and other issues.

2. Should Commission's Energy Division release the Market Price Benchmarks (MPBs) earlier than November 1 of each year? If yes, what is a reasonable date and why?

CalCCA supports retention of the November 1 date for MPBs – a structure that was long considered in Working Group 1. D.19-10-001 sets for the rationale for this deadline, and nothing material has changed since that decision issued.[50] In general, the problems with the November Update referenced above have not been a function of MPB timing.

3. Are there any other procedural or information sharing related modifications the Commission should consider to support more efficient implementation of PCIA issues within ERRA proceedings?

The increases in transparency discussed throughout these comments will support more efficient implementation of PCIA issues within ERRA proceedings. In addition, the Commission can ease parties' review of the proceedings, and reduce the need for discovery and other administrative burdens by requiring the utilities to make consistent their designation of data sets as either confidential or public.

A particularly egregious example of this inconsistency is that SDG&E considers its total portfolio costs to be confidential, whereas PG&E and SCE reasonably provide this data as public. Additional examples of inconsistent confidentiality designations include:

- PG&E and SCE make public vintaged UOG General Rate Case (GRC) costs, procurement costs, and total vintage costs (i.e. the sum of UOG GRC costs + procurement costs). SDG&E provides neither procurement costs nor total costs; they provide only UOG GRC costs.

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50 D.19-10-001, at 11-27 and OP 1.

- PG&E and SCE make public the total system sales, and sales within each vintage, used to derive the PCIA rates, with sales volumes are shown as annual kWh by class; SDG&E does not.
- PG&E and SDG&E make the on-peak and off-peak energy prices in the MPB available publicly; SCE does not.
- PG&E and SDG&E make the list of PCIA-eligible generation resources by vintage available publicly; SCE does not.

CalCCA recommends that the Commission direct consistency among IOUs on these issues with a goal of maximizing the extent of publicly available information.

III. CONCLUSION

For all the foregoing reasons, CalCCA respectfully requests consideration of the proposals 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

January 22, 2021

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

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026 (Filed June 29, 2017)

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

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

Pursuant to the *Assigned Commissioner's Amended Scoping Memo and Ruling* filed December 16, 2020 (Amended Scoping Memo), the California Community Choice Association (CalCCA)[1] submits the following comments and answers to questions. The Amended Scoping Memo directed parties "to file responses to the questions listed in Attachment A. Comments and responses to the questions may be filed and served no later than January 22, 2021."

I. SUMMARY OF COMMENTS ON PROPOSED CHANGES TO PROCEEDING SCOPE

CalCCA supports the Amended Scoping Memo's addition of the following issues to the scope of Phase 2 of this Proceeding:

1) Should the Commission remove or modify the Power Charge Indifference Adjustment (PCIA) cap?

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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, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, 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) Should the Commission modify deadlines or requirements of Energy Resource Recovery Account (ERRA) and PCIA related submittals and reports in order to increase time for parties to review PCIA data and to facilitate timely implementation of decisions in the ERRA proceedings?

3) Should the Commission adopt a methodology for crediting or charging customers who depart from the utility service during an amortization period and who are responsible for a balance in the PCIA Undercollection Balancing Account, the Energy Resource Recovery Account, or any other bundled generation account?

4) Should the Commission consider any other changes necessary to ensure efficient implementation of PCIA issues within ERRA proceedings?[2]

Each of these issues will play an important role in ensuring the stability of the PCIA charge and fostering the ability of Community Choice Aggregators (CCAs) to have equal, transparent and timely access to the data underlying PCIA changes.

Issue 1. CalCCA supports the elimination of the PCIA cap and trigger mechanism to reduce volatility and bring greater stability in the PCIA rate. As a part of agreements with the investor-owned utilities (IOUs) in the most recent Energy Resource Recovery Account (ERRA) forecast proceedings, CalCCA anticipated supporting a petition for modification that the IOUs intended to submit to eliminate the cap and trigger mechanism. [3] The Amended Scoping Memo eliminates the need for this petition. CalCCA discusses its support for cap and trigger elimination in section II of these comments.

Issues 2 and 4: CalCCA members have previously raised concerns regarding the IOU annual ERRA submittals and process. The Scoping Ruling's addition of ERRA process and schedule issues will build on the changes the Commission adopted in recent ERRA forecast

[2] Amended Scoping Memo, at 1.
[3] *See, e.g.*, D.20-12-038 at 12; D.20-12-035 at 52.

proceedings[4] and bring uniformity across the IOUs. In addition to these ERRA-specific rulings, the Commission should require the IOUs to:

- Make available to designated reviewing representatives the following:
    - Confidential versions of the monthly ERRA and Portfolio Allocation Balancing Account (PABA) reports (Monthly Reports) for each month of the year at the time such confidential versions are provided to the Commission; and
    - The same data and workpapers underlying those reports, at the same level of granularity, that are now required to be provided as part of the future ERRA forecast proceedings in each IOU service territory;
- Work with parties to this proceeding to develop non-disclosure agreements (NDAs) that are non-docket specific and specifically allow for reviewing representatives to use the data in the Monthly Reports to create PCIA rate forecasts that do not disclose confidential data and can be shared with market participants; and
- Make consistent their designation of data sets (*e.g.*, total portfolio costs) as either confidential or public across all three IOUs.

Issue 3. CalCCA agrees that crediting or charging customers who depart during an ERRA under- or overcollection amortization period must be addressed. While a common methodology has emerged over the past few years – applying charges or credits to the most recent PABA vintage, which includes both bundled and recently departed customers – the methodology has been applied inconsistently across (and even within) proceedings. Moreover, a timing problem risks misalignment of ERRA costs and cost causation: ERRA proceedings cover calendar years, while customer vintages span calendar years. Consequently, applying charges or credits accrued during a calendar year to a vintage that mixes customers who were bundled customers when the under- or over-collection accrued and departing load customers who were not risks inequitable treatment of one customer category or the other.

[4] D.20-12-035, at Ordering Paragraph (OP) 8; D.20-12-038, at OP 4; D.21-01-017, at OP 6.

II. ANSWERS TO QUESTIONS POSED IN APPENDIX A OF THE AMENDED SCOPING MEMO

A. The Power Charge Indifference Adjustment (PCIA) Cap

1. Should the Commission remove or raise the PCIA cap? Please provide rationale for your answer.

The Commission should remove the PCIA cap. The current iteration of the PCIA cap stemmed from concerns the CCAs had about a lack of transparency underlying, and the resulting inability to plan for, the large swings in the PCIA that can occur both within one year and from one year to the next. CalCCA proposed a collar on the PCIA to promote rate stability,[5] with the understanding that, if the Commission adopted certain of CalCCA's other recommendations (which were rejected), the PCIA would eventually decrease, or increase at a more sustainable rate, allowing for any revenue owed to bundled customers to be paid back in subsequent, low-PCIA years. Instead, the Commission adopted a $0.005/kWh cap proposed by direct access providers and a PCIA trigger proposal from The Utility Reform Network that was based on the existing ERRA trigger mechanism.[6]

The Commission's stated rationale for adopting a cap was to avoid PCIA volatility: "We find that the potential for volatility supports adoption of a PCIA cap in this decision. Such a cap should reduce extreme PCIA price spikes, and bill impacts, but not enable a continual state of significant undercollection.[7] Similarly, "[w]e affirm that a cap protects against volatility in the PCIA."[8] As formally set forth in Finding of Fact 18: "A PCIA cap will limit the change of the

[5] D.18-10-019, at 132.
[6] D.18-10-019, at 134, Finding of Fact (FOF) 19.
[7] D.18-10-019, at 85.
[8] D.18-10-019, at 86.

PCIA from one year to the next. A cap that limits the change of the PCIA from one year to the next promotes certainty and stability for all customers within a reasonable planning horizon."[9]

Unfortunately, the cap has failed to achieve its purpose. Rather than reducing volatility, it has increased volatility and uncertainty. To understand why volatility has increased requires delving into the details of the cap, the associated trigger, and how they have played out in practice.

Soon after adopting a cap, the Commission established balancing accounts – the PCIA Undercollection Balancing Accounts (PUBA) and Cap Balancing Account (CAPBA) -- to "track any obligation that accrues for departing load customers. . . .any balances in the account will be repaid to bundled customers with interest."[10] The cap deferred, not avoided, cost responsibility. In practical terms, unbundled customers borrow from bundled customers to finance the revenue shortfall the utility would otherwise see from application of the cap. The difference between what PCIA customers pay with a capped rate versus what they would have paid with an uncapped rate accrues in a balancing account, for unbundled customers to repay down the road.

When does repayment come due? That depends on how quickly balances build up. In the normal course, "[t]he year-end balances in the balancing accounts established pursuant to sub-paragraph (d)[sic.] above shall be incorporated into the PCIA calculation for the following year."[11] That is, if balances stay below a threshold level, and (by implication) the following year's rate is below a capped level, the prior year's balance will be recouped there. If the next year's rates are also capped, the balancing account will continue to grow. However, if the

[9] D.18-10-019, at FOF 18.
[10] D.18-10-019, at 86; *see also* D.18-10-019, at OP 9(b).
[11] D.18-10-019, at OP 9(c).

balance builds up to a threshold amount within a given year, then a PCIA "trigger mechanism" kicks in, and repayment obligations can arise in the same year that the cap is in effect.

The Commission adapted the PCIA trigger mechanism, and the associated thresholds, from the ERRA trigger mechanism.[12] The PCIA trigger mechanism operates as follows:

a. he PCIA trigger threshold is 10% of the forecast PCIA revenues.

b. If PG&E, SDG&E, or SCE reach 7%, and forecast that the balance will reach 10%, they shall, within 60 days, file expedited applications for approval in 60 days from the filing date when the balance reaches 7%.

c. The application shall include a projected account balance as of 60 days or more from the date of filing depending on when the balance will reach the 10% threshold.

d. The application shall propose a revised PCIA rate that will bring the projected account balance below 7% and maintain the balance below that level until January 1 of the following year.

e. If PG&E, SDG&E or SCE reach 7%, and forecast that the balance will reach 10%, they shall, within 60 days, file expedited following year, when the PCIA rate adopted in that utility's ERRA forecast proceeding will take effect.[13]

Unfortunately, the combination of the cap and trigger has exacerbated, rather than reduced, PCIA rate volatility, due in part to the erroneous assumption seen in paragraph 2 above that a PUBA balance, like an ERRA balance, can somehow self-correct.[14]

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[12] D.18-10-019, at 86.

[13] D.18-10-019, at OP 10(a), (d).

[14] A PUBA balance cannot self-correct because the rate differential between capped and uncapped PCIA rates is fixed (whereas the ERRA rate can decrease if the wholesale cost of electricity decreases). Thus, the only variable that modifies the PUBA balance is the amount of departing customer load. Thus, a PUBA balance cannot decrease, and the rate of accumulation can only slow if departed customers use less load or stop using electricity altogether.

In 2020, PG&E,[15] SCE,[16] and SDG&E[17] all reached the trigger filing threshold of 7% within a few months of 2020 PCIA rates going into effect. Each utility proposed different approaches to drawing down their respective balancing account balances, but the uniform effect was to substantially raise PCIA rates not just to, but above, the capped level (or, in an alternative formulation, to impose an adder atop PCIA rates for unbundled customers, and a credit for bundled customers). In SDG&E's case, it proposed for unbundled customers an astounding 1,438% *month-over-month* increase under one method, or a 230% month-over-month increase under an alternative method.[18]

The Commission mitigated the impacts of these proposals for 2021 by amortizing the balances over three years (rather than three months, as SDG&E proposed,[19] or a single year, as PG&E proposed), and raising the combined PCIA rate and associated surcharge to a level that avoids further balance accruals while amortizing the existing balances. Even with the Commission-approved mitigation approach, unbundled customers are seeing a substantial increase in PCIA rates from 2020 to 2021. On a system average basis, PG&E customers will see PCIA increases up to 40% with SCE and SDG&E increasing up to 55% and 39%, respectively. Moreover, in addition to payback of balances leading to a large increase in unbundled customer PCIA rates, unbundled customers in vintages prior to 2020 are also paying a systemically higher

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15 A.20-09-014, *Expedited Application of Pacific Gas and Electric Company (U 39 E) Under the Power Charge Indifference Trigger*, at 2 (September 28, 2020).

16 A.20-10-007, *Expedited Application of Southern California Edison Company (U 338 E) Regarding the Power Charge Indifference Trigger*, at 1 (October 9, 2020).

17 A.20-07-009, *Expedited Application of San Diego Gas & Electric Company (U 902 E) Under the Power Charge Indifference Adjustment Account Trigger Mechanism*, at 1-2 (July 10, 2020) (SDG&E CAPBA Trigger Application).

18 SDG&E CAPBA Trigger Application, at 6-7 (For a 3-month period, a typical residential departing load customer in the 2015 PCIA vintage using 400 kWh would have seen a monthly increase of $187 (from $13 to $200) using generation revenue allocation factors and of $30 (from $13 to $43) using an equal cents per kWh vintage rate.).

19 SDG&E CAPBA Trigger Application, at 6-7.

PCIA rate than customers in later vintages, as unbundled customers repay the above-cap amounts from 2020.

The key to reducing volatility is to stop the growth of the balances that might cause another trigger in future years while simultaneously drawing down existing balances. And that means eliminating the cap. Unless the cap is eliminated, we may well see a replay of the 2020 scenario in future years, with the added complexity of overlapping multi-year amortizations and vintaged balancing accounts. We need to get off this merry-go-round.

Considering these dynamics, CalCCA members – whose customers are the cap's ostensible beneficiaries – see the cap and trigger mechanism as an added source of uncertainty and volatility. First, because even if capped rates apply in a given year, unbundled customers have to prepare to pay back the looming balancing account balances as those balances build up. Those balances can be substantial, as demonstrated in just the few months of 2020 that gave rise to the utilities' trigger filings.[20]

Second, the deferral is brief. It would only be a one-year deferral under the "normal course" scenario set out in Decision (D.) 18-10-019, before any trigger. With a trigger, the deferral is even shorter. Under SDG&E and PG&E's trigger proposals, the cap would only have been in effect for eight months.[21] After collaborating in the short time allowed within the trigger timelines, CalCCA, its members, and the IOUs joined together in recommending that the balances be amortized over three years rather than just one, but still beginning in January 2021.

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[20] *See* D.20-12-038, at 20 ("PG&E forecasts a year-end PABA under-collection balance of $462 million for 2020, based on recorded data through September 2020 plus a forecast of the remaining three months.").

[21] SDGE's 2020 PCIA rates were effective February 1, 2020 per Advice Letter (AL) 3500-E. The utility's CAPBA proposal would have increased rates beginning in October 2020. PG&E's rates were effective May 1, 2020, per AL 5781-E. PG&E's PUBA trigger proposal would have increased rates beginning January 1, 2021.

Third, drawing down the balances raises unbundled customer PCIA rates above those of bundled customers, all else equal. This creates a competitive imbalance between IOUs and unbundled service providers.

Fourth, uncertainty around whether/when a trigger filing will occur makes rate planning more difficult.

Fifth, and finally, there is significant administrative overhead and litigation expense associated with PUBA and CAPBA trigger filings.

In recognition of these effects, CalCCA agreed with the IOUs to support an end to the cap. We continue to support ending the cap and removing the trigger mechanism and urge the Commission to do so.

2. If you think the PCIA cap should be raised, explain by how much it should be raised and provide rationale for your answer.

CalCCA does not recommend raising the cap amount. Any level of cap will present some or all of the same issues that the current cap presents. True, a higher cap (all else equal) means balances would grow more slowly than they currently do since the difference between capped and uncapped rates is reduced. But the balances will still grow, there could still be trigger filings, and the balances will still have to be repaid leading to higher PCIA rates for unbundled than bundled customers as repayment comes due (see the third point above). The Commission should prevent these dynamics by removing the cap and trigger mechanism.

3. Would removal of the PCIA cap have an impact on Community Choice Aggregators' or Electric Service Providers' overall financial viability? Please provide a financial analysis to demonstrate the impact.

No, for all the reasons discussed in response to question 1. In addition, the cap, after the first year of implementation, does not operate as a cap. This occurs because the trigger amount is recovered as a rider to the capped PCIA rate.[22]

4. What principles or other factors should inform the Commission's consideration of any modifications to the cap and trigger process?

The key principle for any modification to the cap and trigger is whether the modified cap and trigger mitigates PCIA volatility while maintaining a level playing field between bundled and unbundled customers.

5. The investor-owned utilities must file expedited applications for approval in 60 days from the filing date when the trigger balance reaches 7% of forecast PCIA revenues.

a. Should the Commission revisit the 60-day timeframe?

CalCCA proposes to eliminate the cap and trigger mechanism and thus eliminating the need for these expedited applications. If the California Public Utility Commission (Commission) retains the mechanism, however, it should hold workshops describing how to modify the trigger application process. Most critically, any trigger mechanism should avoid same-year rate increases. As the trigger operates now, it can result in multiple PCIA increases in a year, increasing uncertainty and impairing CCA planning.

22 *See, e.g.,* D.20-12-035, at OP 1; D.20-12-038, at OP 6 (ordering SCE to apply a "PCIA Trigger Mechanism Surcharge" to departed load customers in addition to the capped PCIA rate).

b. Are there other modifications to the PCIA trigger mechanism that the Commission should consider, such as revisiting the PCIA trigger amount currently set to 10 percent of forecast PCIA revenues? If so, explain in detail the proposed modification and provide rationale for your answer.

CalCCA proposes to eliminate the cap and trigger mechanism, thus eliminating the need to consider trigger thresholds. If the Commission elects to retain the cap and trigger mechanism, CalCCA recommends workshops to consider this and other questions.

6. Should the PCIA cap be applied to the prior year's forecast PCIA rate, or each prior year's final PCIA rate that includes the true-up recorded actuals for energy and the Commission-issued final Resource Adequacy (RA) and Renewables Portfolio Standard (RPS) adders? Provide rationale for your answer.

CalCCA proposes to eliminate the cap and trigger mechanism and thus eliminating the need for to consider the mechanics of cap application. If the Commission elects to retain the cap and trigger mechanism, CalCCA recommends workshops to consider this and other questions.

7. Should the Commission adopt a methodology for crediting or charging customers who depart from the utility service during an amortization period and who are responsible for a balance in the PCIA Undercollection Balancing Accounts, the Energy Resource Recovery Account (ERRA), or any other bundled generation account? Explain in detail what methodology you recommend and provide rationale for your answer.

Yes, the Commission should develop and adopt a uniform methodology for addressing the application of ERRA charges or credit to bundled and departing load. To some degree, a common methodology has emerged via recent ERRA and PUBA/CAPBA trigger proceedings, but the methodology has been applied inconsistently across (and even within) proceedings and suffers from a significant short-coming resulting from a timing mismatch between ERRA forecast periods and customer vintage periods. Thus, in establishing this methodology, the Commission should consider the distortions and equities that could result from such a mismatch.

The methodology also should make certain that cost recovery or credit aligns squarely with cost causation. Lastly, the methodology should be applied uniformly across utilities and proceedings.

Before the details of this question can be considered, however, the question itself requires some clarification. It suggests that a customer departing utility service might be "responsible for a balance in the PCIA Undercollection Balancing Accounts." However, customers departing utility service can only be *owed* a PUBA balance from when they were bundled customers (*i.e.*, the customers overpaid their obligations on account of the PCIA rate cap when they were bundled customers and then departed). Departing customers would only be "responsible" for a PUBA balance if they were departed customers when a PUBA balanced accrued and then opted out to *return* to bundled service (*i.e.*, the customers underpaid their obligations on account of the PCIA rate cap when they were unbundled customers and then returned to bundled service).

With that clarification in mind, yes, the Commission should adopt a common methodology for all utilities for crediting or charging customers who depart from utility <u>or CCA</u> service during an amortization period and who are responsible for, <u>or owed</u>, a balance in the PUBA/CAPBA, the Energy Resource Recovery Account, or any other bundled generation account.

a. A Uniform Application of Methodologies to Credit or Charge Bundled and Recently Departed Customers Is Needed

Generation balancing accounts such as those for bundled ERRA rates accrue overcollections when rates are either set too high, or demand exceeds forecasted loads, over the course of a year. These overcollections represent a refund owed to customers that should be paid back to those customers. The inverse problem arises for charges to recover undercollected balances. In recent ERRA forecast and trigger proceedings, stakeholders and the Commission have coalesced around a methodology that credits (or charges) the most recent vintage in the

PABA to effectuate the refund by reducing the future generation rates customers will pay (rates would increase in the event of an undercollection). Since both bundled and unbundled customers pay the PCIA, the reduction in the PABA effectively refunds most customers that are owed a credit (and charges most customers that have underpaid).

PG&E's 2020 ERRA forecast case demonstrates this approach. In D.20-02-047, the Commission agreed with the Joint CCAs that a net ERRA overcollection must be reflected in the PCIA rate, and that the "overcollection credit should benefit all customers who paid into the overcollection."[23] The Commission ordered PG&E to "include in its Energy Resource Recovery Account Forecast application for 2021 a method to properly credit vintage 2019 and 2020 departed load customers that does not have adverse effects on PCIA vintage subaccounts."[24]

PG&E proposed returning the end-of-year ERRA balance going forward, "less the deferred revenue financed by bundled customers due to capped PCIA rate," to the 2020 vintage and that this approach be standardized for future years.[25] PG&E explained the purpose of the transfer is to "ensure that the 2020 overcollected ERRA is returned to the Vintage 2020 non-exempt departing load customer and remaining bundled customers."[26] Because customer vintages are determined on a July to June schedule, PG&E's proposal to transfer year-end ERRA balances to the most recent vintage on a going-forward basis would ensure customers departing

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[23] D.20-02-047 at 11.
[24] D.20-02-047 at OP 4.
[25] A.20-07-002, Exh. PG&E-1 at 19-7:6-15 and 19-4:22-25. PG&E also proposed to credit a proportional share of the 2019 ERRA end-of-year balance to 2019 vintage departing load customers through a one-time PCIA rate adjustment for that vintage. A.20-07-002, *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, at 5, 12-13, 18, 21 (July 1, 2020).
[26] *Id*. at 14-14:2-4.

"on or after July 1" are credited (or charged) for the ERRA balance accruing during the year of their departure.[27]

The Commission adopted PG&E's approach in D.20-12-038 but, as discussed in more detail below, did not determine it should be applied in all future years because it did not address all customers that were owed a refund.[28] Nonetheless, similar approaches have also been adopted with regard to ERRA trigger undercollections in SCE's service territory (A.18-11-009),[29] and with regard to CAPBA financing in SDG&E's service territory (A.20-07-009).[30] SDG&E's ERRA Trigger Application, A.20-12-007, also proposes a one-time transfer to PABA to address an ERRA undercollection that accrued during 2020.[31]

There are two shortcomings with this approach. First, it has been inconsistently applied to recently departed customers who, like bundled customers, financed a PUBA balance. For example, over the Joint CCAs' objections, D.20-12-038 returned PG&E's PCIA Financing Subaccount (PFS) to bundled customers via the ERRA rather than the PABA.[32] As a result, some of the funds owed to currently bundled customers who depart PG&E service during the amortization period will never receive them. Because returning an ERRA overcollection to bundled customers has the same effect as reimbursing bundled customers for having financed the

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27 A.20-07-002, Exh. JCCAs-1 at 37:20 to 38:3.

28 D.20-12-038, at 22.

29 *See* D.19-01-045, at OP 2 (stating "Southern California Edison Company shall collect the Energy Resource Recovery Account undercollection through a pro-rata apportionment of the costs to 2018 SCE bundled service customers, including 2018 and 2019 vintage departing load customers, utilizing bundled service allocation factors established in D.18-11-027, and using the Power Charge Indifference Adjustment as the rate recovery vehicle for the undercollection amount.").

30 D.20-12-028, at OP 4 (ordering "a one-time transfer of the CAPBA overcollection due to bundled customers into the 2020 vintage of its Portfolio Allocation Balancing Account").

31 A.20-09-014, *Expedited Application of San Diego Gas & Electric Company (U 902 E) Under the Energy Resource Recovery Account Trigger Mechanism*, at 2 (December 11, 2020); A.20-09-014, *Prepared Direct Testimony of Stacy Fuhrer on behalf of SDG&E*, SF-8 (December 11, 2020).

32 D.20-12-038 at 21-22.

PUBA,[33] the Joint CCAs argued it should have been 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."[34] This approach would have comported with an approach already codified in SCE's PABA implementing advice letter, which returns the PUBA balance via the PABA, ensuring customers that are owed a refund would receive one.[35]

The PG&E decision did not, and could not, explain why those purported differences warrant such an inequitable outcome. The decision states only that "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."[36] That is, the decision promoted PG&E's preferred accounting treatment over providing full refunds to ratepayers that paid into a balance they were owed. However, the Commission did state it "may consider structural changes to the [PFS] when we address PCIA framework issues in the appropriate proceeding."[37] The Commission should address such revisions as part of this proceeding.

More broadly, recent decisions establishing three-year amortization periods for the PUBA balances for PG&E and SCE and the CAPBA for SDG&E did not address customer

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33 A.20-07-002, Exh. JCCAs-1 at 41:11-13.

34 D.20-02-047, at 11.

35 SCE AL 4084-E and SCE Preliminary Statement Section Q.3.b (stating "The year-end balance in this subaccount is returned, in its entirety with interest, through a transfer to the applicable vintage subaccount of the PABA.").

36 D.20-12-038 at 21-22.

37 D.20-12-038 at 21-22.

crediting for years other than 2021.[38] Thus, a crediting methodology must still be developed (and uniformly implemented) for 2022 and 2023.

CalCCA supports the approach that has emerged over recent years, which most closely aligns cost responsibility with cost causation, but it must be applied uniformly. Transferring the amount due customers who were bundled customers at the time the cost was incurred to the recent PABA vintage(s) ensures that all customers – bundled or recently departed – receive credit for their share of an ERRA overcollection or PUBA/CAPBA balance they helped finance. This approach aligns with long-standing ratemaking principles, is simple to implement, and will produce a uniform approach for balancing account under collections across all utilities.

b. The Problem Is Complicated by the Mismatch Between the Vintaging Methodology and Ratemaking Calendar

The second shortcoming with the current approach is that customers that depart in the first half of a year in which an overcollection accrues are unlikely to receive any credit for refunds they are owed (with the inverse being true in the case of an undercollection). This issue stems from the fact that vintages are set with a mid-year cutoff, while PCIA and ERRA rates are (generally) set on a calendar year basis. A hypothetical overpayment through, say calendar year 2019, if refunded to *vintage* 2019 will be underinclusive. Why? Because the vintaging rules' June cut-off means *vintage* 2019 does *not* include customers who departed January through June 2019. Those customers are vintage 2018. So even though they left IOU service in 2019 and

[38] D.20-12-028, at OP 4, at 22 (SDG&E) ("We recognize the importance of approving a consistent method for returning balances to customers but will not adopt PG&E's going-forward proposal at this time. We will consider a long-term solution when we address PCIA framework issues in the appropriate proceeding."); *id.* at 9 ("In this decision we do not rule on SDG&E's argument, made in its reply briefs, that the Commission should require departing customers leaving SDG&E in the middle of 2021 to forgo a refund, though we do approve a one-time transfer of the CAPBA overcollection due to bundled customers into the 2020 vintage of PABA."); *see* D.20-12-035, at OP 6 (SCE); *see also* D.20-12-038, at 18, OP 1 (PG&E).

would have contributed to the amount being refunded, they would not see a refund. While you could pick those customers up by refunding to the 2018 vintage, now you would be overinclusive, since some of the 2018 vintage customers would in fact have left in calendar 2018, and not contributed to the amount being refunded.

This quandary was considered in the PG&E 2021 ERRA forecast case above, where customers receiving a credit were those who departed on or after July 1, 2020 (or remained bundled PG&E customers) and paid into ERRA for at least the first half of 2020.[39] However, customers that overpaid in 2020, but left during the first half of 2020, would not receive a refund to which they are entitled when the most recent vintage (in this case, 2020) is credited via PABA because those customers are 2019 vintage customers. Stated another way, the refund misses "half" the vintage.

It was for this reason the Commission did not formally adopt PG&E's approach of crediting the most-recent vintage on a going-forward basis.[40] As part of this expanded proceeding, the Commission should explore how to resolve this problem consistently and equitably, by revising the vintaging rules, modifying the ratemaking calendar, or another approach.

B. Improving PCIA and ERRA Alignment

1. How should the Commission modify the deadlines and requirements of ERRA and PCIA-related submittals and reports in order to increase time for parties to review PCIA data while facilitating an ERRA implementation on January 1 of each year? Explain in detail the proposed modification and provide rationale for your answer.

The CCAs have repeatedly requested opportunities to revise the annual ERRA process, and resulting Annual Electric True-Up (AET), to ensure both stakeholders and the Commission

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39 A.20-07-002, Exh. JCCAs-1, Attachment B, PG&E's response to Joint CCA DR 3.34.

40 D.20-12-038, at 22.

have sufficient time to adequately analyze the complex and high-stake issues in an ERRA proceeding, while also acknowledging the need to litigate the proceeding on an expedited timeline. In 2019, the CCA parties to PG&E's ERRA Forecast proceeding sought "Commission guidance for a forum in which more concrete procedural mechanisms might be adopted for all IOU ERRA processes."[41] CalCCA appreciates the Assigned Commissioner's response by amended the Scoping Ruling for this phase.

Thematically, the challenges parties (and, by extension, the Commission, where it relies on parties for record development) face break down into two categories:

(1) Challenges accomplishing needed work given unusually short deadlines, and

(2) Challenges obtaining needed information from utilities (which then exacerbate problem (1)).

The Joint CCAs laid these challenges out graphically back in 2019. Harking back to the experience of 2018, Joint CCAs stated:

> Addressing the November Update was a difficult task—an exercise in legal triage that barely maintained due process thanks to an extraordinary ALJ ruling and the unusual but necessary step of requiring a Tier 2 Advice letter to implement an ERRA forecast decision. It required analyzing 80 pages of updated testimony, scrutinizing 13 sets of workpapers, participating in two informal workshops, submitting and reviewing responses from two sets of discovery totaling 29 data requests (excluding tens of additional sub-parts), drafting 35 pages of comments, and submitting a Motion to add 15 exhibits to the record. The parties had ***<u>10 days</u>*** to accomplish all of these tasks, which turned into 12 days given the timing of the update resulted in a Saturday deadline.[42]

[41] A.19-06-001, *Protest of the Joint CCAs to the Application of Pacific Gas and Electric Company (U 39 E) for 2020 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast And Greenhouse Gas Forecast Revenue Return And Reconciliation*, at 28 (July 5, 2019) (referencing, A.18-06-001, *Assigned Commissioner's Scoping Memo And Ruling*, at 4 (Aug. 16, 2018)).

[42] *Id.* at 30.

It is incumbent upon CCAs to assist the millions of unbundled customers in California in planning for rate changes in the ERRA that, in the past, have led to significant, volatile and near-term changes in customers' monthly electricity bills. The opacity of IOU filings, and the Commission's ERRA framework in general, have repeatedly and consistently frustrated CCAs' efforts to advocate for their customers.

a. Master Data Requests and More Detailed and Timely Workpapers Are Necessary to Ensure Full and Fair Data Access by Customers Paying the PCIA

In each of its recent ERRA forecast decisions, the Commission took strides toward leveling the playing field within those proceedings and increasing LSEs' ability to predict and plan for PCIA rate changes that primarily rely on confidential, utility-specific cost and revenue data. For example, in D.20-12-035, the Commission found that "[c]ertain market participants, including CCAs, require timely access to SCE's ERRA/PABA/PUBA reporting as well as precise volume of RA, RPS and other metrics in order to meet their evidentiary burden in the ERRA forecast proceeding."[43] It further determined that delaying access to the "ERRA/PABA/PUBA and other reports concerning the validity of SCE's ERRA forecast application until the November Update, and requiring extensive discovery requests to obtain this information, creates additional administrative burdens for the parties to the proceeding as well as Commission staff."[44]

The Commission required SCE to "provide the following information in Energy Resource Recovery Account (ERRA) forecast proceeding workpapers and monthly ERRA compliance reports, starting January 2021:

(a) Confidential version of monthly ERRA/PABA/PUBA activity reports;

[43] D.20-12-035, FOF 38.
[44] D.20-12-035 at 56.

(b) Additional detail supporting the monthly PABA reports, including subcategories for summarized line items such as utility-owed generation (UOG) costs and contracts (*e.g*., provide by resource type, and whether Renewables Portfolio Standard (RPS) or non-RPS eligible);

(c) Actual or accrued 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 accrued volumes of Actual Sold, Retained, and Unsold Resource Adequacy capacity; and

(e) Monthly accrued volumes of Actual Sold, Retained, and Unsold RPS-eligible energy.[45]

The Commission made nearly identical findings and orders in both PG&E and SDG&E's ERRA Forecast decisions, requiring a Master Data Request in the PG&E case.[46] The Commission also specified in that case the following process: "After PG&E has filed an ERRA forecast application, and so long as such application is pending, PG&E will provide the specified information to reviewing representatives that have signed a nondisclosure agreement within 5 days after it submits each monthly ERRA/PABA/PUBA activity report to the Commission."[47] Requiring the data in the SCE case be provided, and this PG&E process to be followed, by all IOUs in their respective ERRA Filings will ensure uniformity in CCAs' access to data and significantly improve transparency in these expedited and opaque proceedings.

b. Equal, Transparent and Timely Access to Data are Necessary During all 12 Months of the Year.

The ability of CCAs to have equal, transparent and timely access to the data underlying changes to the PCIA has been a consistent point of contention for many years. Under the Commission's indifference framework, the PABA and the PCIA are inextricably linked to IOU

45 D.20-12-035 at OP 8.
46 D.20-12-038, 31-32 and OP 4; D.21-01-017 at OP 6.
47 D.20-12-038, 31-32, Conclusion of Law 11, and OP 4.

data the CCAs currently cannot access on a periodic basis outside of an active ERRA proceeding. This prohibition even applies to the CCAs' reviewing representatives under D.06-06-066 and the Commission's confidentiality framework. Those data include foundational data such as actual retail customer sales, which can significantly impact the PABA due to typical factors like weather and atypical factors like the COVID-19 pandemic and the IOUs' Public Safety Power Shut-off events.

As D.20-12-038 recognizes, each utility "already provides certain data regarding its ERRA/PABA/PUBA balances and other metrics associated with its ERRA forecast to the Commission on a monthly basis."[48] However, the monthly reports do not include volumetric data, which is necessary to understand why the PCIA is moving the way it is moving and to predict where the PCIA may head in the future based on different scenarios.

Thus, while the actions the Commission took to increase transparency in the ERRA Forecast proceedings will be helpful, year-round access to key cost and revenue data for the CCAs' designated reviewing representatives is the next critical step. Only year-round access to data achieves a level playing field in LSEs' ability to plan for PCIA rate changes and accurately forecast which direction those changes will go. As D.20-12-038 recognizes, "[g]ranting independent consultants access to confidential market sensitive information, under appropriate non-disclosure agreements, is a reasonable means of allowing market participants to review confidential versions of ERRA/PABA/PUBA reports."[49]

For this reason, the Commission should require the IOUs to make available to designated reviewing representatives the following:

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48 D.20-12-035, Conclusion of Law 39.

49 D.20-12-035, OP 5.

- Confidential versions of the Monthly Reports for each month of the year at the time such confidential versions are provided to the Commission; and
- The same data and workpapers underlying those reports, at the same level of granularity, and within the same schedule, that is now required to be provided as part of future ERRA forecast proceedings in each IOU service territory.

In light of the fact that much of the information contained in these reports is confidential, it would be appropriate for the Commission also require the IOUs work with parties to this proceeding to develop NDAs that are non-docket specific, *i.e.*, NDAs that would apply to year-round provision of confidential data. The NDAs should also specifically allow for reviewing representatives to use the data provided in the Monthly Reports outside the context ERRA Forecast proceedings for the limited purpose of creating PCIA rate forecasts that are based on, but do not disclose, confidential data, and can be shared with CCA decision-makers to allow them to plan for future rate changes.

c. Discovery Timelines Should Be Tightened

Subject to the caveat that parties reasonably limit the number of requests, CalCCA suggests the following discovery timelines:

- Between the Application Date and Rebuttal Testimony – 10 Business Days (BDs)
- Between Intervenor Testimony and IOU Rebuttal Testimony – 5 BDs
- Between IOU Rebuttal Testimony and Hearings – 3 BDs
- Between final Update and Comments to final Update (or Intervenor Updated Testimony) – 2 BDs

In addition, parties should be required to serve workpapers concurrently with testimony and any updated or supplemental testimony in each ERRA forecast proceeding, and all workpapers should have (a) formulas intact, (b) underlying data included, and (c) avoid the use of hard-coded data that have little value.

d. A Modified Schedule Is Required to Reduce the Year-End Chaos Arising from November Updates

The Scoping Ruling rightly identifies the need to consider modifications of the current ERRA forecast requirements and schedules to bring greater transparency and efficiency to the process. While CalCCA is still considering the details of a modified schedule, certain issues warrant initial consideration. Most critical to CalCCA is ensuring the use of most current possible pricing data for market price benchmarks in ERRA forecast proceedings. Depending upon the broader direction of any changes, schedule modifications could include the following:

- ✓ Advance the submittal date for the November Update by one week.
- ✓ Following the November Update, set the following intervals for submittals:
    - o Comments on the November Update would be due between 12 and 15 days after its submittal, depending on how calendar plays out;
    - o Parties would be required to use their best efforts to respond to data requests within 3 business days;
    - o Comments on a proposed decision (PD) would be due between 7 and 10 days before meeting date at which the decision will be adopted;
    - o Reply comments on the PD would be due three days before the adoption meeting.

Finally, the Commission should consider the timing of PG&E's Annual Electric True-Up advice letter to avoid year-end confusion.

Optimally, however, schedule issues should be explored collectively among stakeholders, Key questions to explore include the following:

- Whether/how to constrain the final update in ERRA forecast proceedings to "turn of the crank" type changes (e.g., MPB updates), and avoid the surprises and litigation seen in the past several ERRA forecast proceedings;
- How to stagger IOU filings to reduce overlapping deadlines for staff common to multiple IOU ERRA proceedings;

- Whether to push the implementation date for new rates from January 1, 2021 to a later date; and

- Whether to push back the annual electric true-up filing for PG&E.

CalCCA recommends a workshop to explore these and other issues.

2. Should Commission's Energy Division release the Market Price Benchmarks (MPBs) earlier than November 1 of each year? If yes, what is a reasonable date and why?

CalCCA supports retention of the November 1 date for MPBs – a structure that was long considered in Working Group 1. D.19-10-001 sets for the rationale for this deadline, and nothing material has changed since that decision issued.[50] In general, the problems with the November Update referenced above have not been a function of MPB timing.

3. Are there any other procedural or information sharing related modifications the Commission should consider to support more efficient implementation of PCIA issues within ERRA proceedings?

The increases in transparency discussed throughout these comments will support more efficient implementation of PCIA issues within ERRA proceedings. In addition, the Commission can ease parties' review of the proceedings, and reduce the need for discovery and other administrative burdens by requiring the utilities to make consistent their designation of data sets as either confidential or public.

A particularly egregious example of this inconsistency is that SDG&E considers its total portfolio costs to be confidential, whereas PG&E and SCE reasonably provide this data as public. Additional examples of inconsistent confidentiality designations include:

- PG&E and SCE make public vintaged UOG General Rate Case (GRC) costs, procurement costs, and total vintage costs (i.e. the sum of UOG GRC costs + procurement costs). SDG&E provides neither procurement costs nor total costs; they provide only UOG GRC costs.

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50 D.19-10-001, at 11-27 and OP 1.

- PG&E and SCE make public the total system sales, and sales within each vintage, used to derive the PCIA rates, with sales volumes are shown as annual kWh by class; SDG&E does not.
- PG&E and SDG&E make the on-peak and off-peak energy prices in the MPB available publicly; SCE does not.
- PG&E and SDG&E make the list of PCIA-eligible generation resources by vintage available publicly; SCE does not.

CalCCA recommends that the Commission direct consistency among IOUs on these issues with a goal of maximizing the extent of publicly available information.

III. CONCLUSION

For all the foregoing reasons, CalCCA respectfully requests consideration of the proposals 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

January 22, 2021

January 24, 2021

Re: Joint Agency Comments on Volkswagen Light Duty Electric Vehicle Infrastructure Program

These comments are submitted by Peninsula Clean Energy Authority (PCE), Sonoma Clean Power, East Bay Community Energy, MCE (formerly Marin Clean Energy), and Redwood Coast Energy Authority ("Joint Agencies"). The Joint Agencies appreciate the opportunity to provide feedback to the Bay Area Air Quality Management District (BAAQMD) on the Volkswagen Mitigation Trust, Light-Duty Zero-Emission Infrastructure Program, which will inform the design of electric vehicle charging infrastructure across the state.

In these comments, the Joint Agencies recommend that the BAAQMD:

1. Expand the applicant eligibility criteria beyond just organizations that own and operate EV charging stations;
2. Increase the incentive levels for Electric Vehicle Supply Equipment (EVSE) installations at multifamily housing;
3. Allow incentives to be used for assigned parking at multifamily housing;
4. Encourage the use of Level 1 and power-managed Level 2 charging to yield additional EVSE deployment;
5. Increase the minimum Direct Current Fast Charger (DCFC) power threshold to 100+ kW and only require no more than one CHAdeMO adapter per site.

I. Expand the Applicant Eligibility Criteria Beyond Just Organizations That Own and Operate EV Charging Stations

The program lists as its primary goal "to support the expanding fueling needs of a growing electric vehicle fleet across the state." Among the target sites listed are "Multi-Dwelling Units" (MDU), "Workplace Facility," "Destination," and "Transit." However, the current design of the program will likely result in little or no charging deployed at MDUs, Workplaces, and Transit locations as well as limited deployments in Destination sites.

MDUs, Workplaces and Transit are “long-dwell” sites in which vehicles are parked for extended periods of time, typically 6 to 12 hours. In these sites, Level 2 (and Level 1, see below) is the optimal form of charging as they provide ample charging capacity for the dwell time at reasonable installation cost. In a 6-hour window, a typical Level 2 charger at 7.2 kW would provide approximately 150 miles of charge. A Level 2 port (without power management, see discussion below) typically costs $6,000 to $12,000 to install. By contrast DCFC is not suitable to serving such locations as the high costs of $50,000 to $100,000+ per port would substantially limit the number of ports that could be deployed at such sites. The long dwell times would also result in considerable underutilization of the chargers as vehicles would stay plugged into the station long after they’ve received sufficient charge, barring expensive onsite staffing for valet management of vehicles which is likely to be found at very few sites, particularly for overnight MDU parking.

As a result, the overwhelming majority of relevant ports at these sites are Level 2. In addition, those charging systems are almost universally owned and operated by the property owners themselves. However, the draft solicitation limits applicants to only equipment vendors and contractors and requires that those companies own and operate the equipment. But vendor owner-operation is a business model almost exclusively found among DC fast charging companies. There are no major, or possibly even any, owner-operator vendor companies for Level 2 charging serving MDUs, Workplace, and Transit. This is unsurprising because the revenue potential is nominal as pricing high above power costs makes the charging service uneconomical for drivers as well as property owners. Even with high utilization, the revenue potential is far too low to sustain an owner-operator business model in most cases. By limiting eligible applicants only to vendors that own and operate charging stations, the BAAQMD is significantly limiting the number of applicants and locations that can apply and the types of projects that will be funded.

It seems highly unlikely that EV charging companies that utilize an owner/operator model will choose to install Level 2 charging at MDUs, Workplaces and Transit, as well as many Destination sites. Therefore, the grant is effectively excluding these kinds of projects in favor of DC fast charging and the kinds of sites served by fast charging, namely short dwell Destinations and Corridors. The Joint Agencies encourage the BAAQMD to eliminate this eligibility restriction and allow for more EV charging project types to be funded in this program, particularly at MDUs.

II. The BAAQMD Should Provide Higher Incentives to EVSE installations at Multifamily Housing

While EV adoption is growing across the state, roughly one-third of Californians that live in multifamily housing where they typically do not have access to home charging. This presents a significant barrier to EV adoption. Furthermore, adding EV charging at multifamily housing can be more complex and costly than an EVSE installation at a single-family home. Both technical and financial assistance are critical to support EV adoption among multifamily housing residents. As such, incentive levels should reflect the complex challenge of installing EVSE at these sites. Based on these factors, the Joint Agencies support increasing the incentive higher than the current funding cap of 60% as a key means to support EV adoption in the multifamily housing context.

III. Allow EVSE Incentives to be Utilized for Assigned Parking at Multifamily Housing

The Draft Guidance is silent on the issue of shared parking vs assigned parking at MDUs. The Joint Agencies encourage the BAAQMD to explicitly allow funding to be used for assigned parking at multifamily housing, in addition to shared parking. Some industry consultants estimate that as much as 80% of parking spaces at multifamily housing properties are often deeded or assigned to residents. Tenants are also unable to switch parking spaces. The Joint Agencies therefore caution against limiting funding to shared parking only as it limits the scale of investment that to parking that does not exist at most multifamily properties. Furthermore, the Americans with Disabilities Act (ADA) imposes requirements when creating a new shared parking spaces within an existing multifamily property that often mean such projects are seen as nonstarters among multifamily property owners. Allowing for funding to be utilized for Level 1 or power-managed Level 2 EVSE installations at assigned parking will allow multifamily properties to more easily explore deployment scenarios where every tenant can get access to EV charging.

This is a critical component of an equitable push for EV adoption. There are multiple funding programs that assist in the purchase of a vehicle, but very limited resources available to address charging needs the other critical component of EV ownership: charging the vehicle. Allowing for the inclusion of assigned parking spaces at multifamily housing will create more opportunity for low-income Californians to transition to EVs.

IV. Encourage the Use of And Provide Financial Support for Level 1 and Power-Managed Level 2 Charging to Yield Additional EVSE Deployment

Both Level 1 and power-managed Level 2 charging with 1.4 kW minimum capacity offer the ability for multifamily housing managers/owners to meet the daily charging needs of their residents as they provide a minimum of 40-50+ miles of range or more per overnight charge. The Joint Agencies encourage the BAAQMD to allow multifamily property owners/managers to choose for the technology option that makes the most sense for their development based on individual factors, such as unique installation circumstances, project cost savings, or convenience for residents.

Level 1 charging is an excellent low-cost charging option to provide access to EV charging for multifamily residents. Level 1 charging is already in widespread use among current EV owners. A report[1] by the California Air Resources Board shows that over half of all EV drivers are successfully using Level 1 charging to charge their vehicle through either a standard outlet or Level 1 EVSE. Furthermore, the cost of installing Level 1 charging can be considerably cheaper than traditional Level 2 charging, allowing the BAAQMD program to yield additional EV charge ports.

Advanced load management systems (ALMS), also referred to as “power managed Level 2” charging in these comments, are a key strategy in expanding the total possible deployment of traditional Level 2 EVSE by utilizing energy controls. The Joint Agencies encourage the BAAQMD to explicitly incorporate the utilization of these technologies in program design as a strategy to expand the number of EV charge ports possible at a site without incurring expensive electrical infrastructure upgrades.

Both Level 1 and power-managed Level 2 charging can significantly lower the cost of EVSE installations. The installed cost for Level 1 charging can run as low as under $2,000 per port and power-managed Level 2 charging under $4,000 per port within a given service capacity (with power-managed Level 2 providing higher service levels generally). The actual cost savings grow substantially when factoring the avoided costs of increasing service capacity. Increasing distribution grid service capacity can raise costs by tens of thousands of dollars. Level 1 and power managed Level 2 can provide as many as four (4) ports or more within a given 40-amp circuit whereas that same capacity might only support one conventional unmanaged Level 2 port. Costs for unmanaged Level 2 ports can run as high as $18,000 per port as reported by PG&E on their EV Charge Network program.[2] As a consequence, the overall costs to achieve the state’s target of 250,000 ports by 2025 can be reduced substantially with the inclusion of Level 1 and power-managed Level 2. These lower-cost options also open up opportunities for more widespread EV adoption, particularly as EV ownership evolves beyond affluent early-adopters.

V. Increase the Minimum DCFC Power Threshold to 100 kW+ or More and Remove the Requirement that Each DCFC Contain both an SAE and CHAdeMO Connector

The Joint Agencies recommend that the BAAQMD should increase the minimum power requirement from 40 kW to 100 kW+ for DC fast chargers and not require both an SAE CCS and CHAdeMO connector per station.

DCFC is a critical element to support and drive the adoption of EVs in California. Supporting faster charging technologies is necessary to provide adequate charging options and capabilities to future EV owners for several reasons. First, faster charging enables a higher through-put per site so more cars can utilize a port on a daily basis, thereby increasing efficiency of the infrastructure and the capital investment used to fund the stations. Second, as the suite of EVs on the market increases and improves, larger batteries may necessitate quicker charging technologies to maximize the usefulness and range of those vehicles. Third, critics of EVs cite the refueling or recharging speed relative to internal combustion engine (ICE) vehicles as a reason to avoid purchasing EVs. These factors all suggest that increasing the minimum power threshold of DCFC should be the requirement moving forward.

This program should also remove the requirement that DCFC have both a CCS and CHAdeMO connectors, and instead require a minimum of one CHAdeMO connector be installed per *site* at locations with multiple DCFC. Early EVs, primarily from Japanese automakers such as Nissan, used the CHAdeMO standard to serve DCFC needs. Nearly all other automakers use the CCS standard for DCFC needs. Recently, Nissan stated that future EVs will not include CHAdeMO as the DCFC standard and instead switch to CCS standard. Over the lifetime of the DCFC infrastructure, the EV population will increase rapidly thereby relegating vehicles with CHAdeMO standards to a small percentage of the vehicle fleet. In addition, charger manufacturers are now developing dual-port stations capable of charging in both ports concurrently, a major advance that improves service levels, lowers installation costs, and improves business viability. However, concurrent dual-port stations are only feasible with CCS. Continuing to require multiple CHAdeMO connectors per site is inconsistent with future EV industry trends, DCFC technology development, and driver usage. As the market continues to evolve, the BAAQMD should continue to monitor the changes and possibly consider removing the requirement to have any CHAdeMO connectors in future grant programs.

If you have any questions regarding these comments, please do not hesitate to contact us.

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[1] https://ww2.arb.ca.gov/sites/default/files/2020-01/appendix_b_consumer_acceptance_ac.pdf

[2] PG&E EV Charge Network Quarterly Report (July 1, 2019 – September 30, 2019), p. 13, available athttps://www.pge.com/pge_global/common/pdfs/solar-and- vehicles/your-options/clean-vehicles/charging-stations/program-participants/PGE-EVCN-Quarterly-Report-Q3- 2019.pdf (reflecting PG&E's average cost per port of $17,973 through Q3 2019 in the EVCN program)

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Concerning Energy Efficiency Rolling Portfolios, Policies, Programs, Evaluation, and Related Issues.	Rulemaking 13-11-005 Filed November 14, 2013

MARIN CLEAN ENERGY NOTICE OF EX PARTE COMMUNICATION

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January 26, 2021

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Concerning Energy Efficiency Rolling Portfolios, Policies, Programs, Evaluation, and Related Issues.	Rulemaking 13-11-005 Filed November 14, 2013

MARIN CLEAN ENERGY NOTICE OF EX PARTE COMMUNICATION

Pursuant to Public Utilities Code Section 1701.1(e)(3), 8.2(c)(3), and Rule 8.4 of the California Public Utilities Commission's Rules of Practice and Procedure, Marin Clean Energy ("MCE"), hereby provides notice of an *ex parte* communication in the Rulemaking 13-11-005.

On January 22, 2021 at approximately 3:00 PM, Leuwam Tesfai, Chief of Staff and Legal Advisor to Commissioner Shiroma, and Cheryl Wynn, Energy and Water Advisor to Commissioner Shiroma, met with the following individuals from MCE: Jana Kopyciok-Lande, Senior Policy Analyst; Alice Havenar-Daughton, Director of Customer Programs; Shalini Swaroop, General Counsel and Director of Regulatory and Legislative Policy; Vicken Kasarjian, Chief Operating Officer; and Dawn Weisz, Chief Executive Officer. The communication took place via teleconference. MCE initiated the communication and provided the PowerPoint presentation as seen in Attachment A. The PowerPoint presentation was sent at 9:04 AM on January 22, 2021 which is why this communication is being tendered for filing late.

During the meeting, MCE representatives discussed their role as a program administrator of ratepayer-funded energy efficiency ("EE") programs. Ms. Weisz opened up the meeting by highlighting MCE's interest in offering EE programs to vulnerable customers that need help the most, especially considering the current challenges surrounding the Covid-19 pandemic. Ms. Weisz noted that ratepayer-funded EE programs are expected to fulfill multiple policy objectives which are not appropriately supported by a single cost-effectiveness metric.

Ms. Havenar-Daughton then presented four specific policy recommendations: first, MCE supports the proposal to split the EE portfolio into three sub-portfolios to distinguish between resource, equity and market transformation programs. This will allow for setting separate goals for the different sub-portfolios and measuring the success of each portfolio per the distinct policy objectives. Second, MCE recommends that resource programs should use the program administrator test ("PAC") instead of the total resource cost ("TRC") test to better align costs with benefits. Third, MCE proposes to broaden eligibility for equity programs beyond residential customers. Fourth, MCE suggests that non-energy benefits ("NEBs") should be considered in the cost-effectiveness calculation for EE equity programs.

In closing, Ms. Weisz reminded the Commission of the important role Community Choice Aggregators ("CCAs") can play in implementing EE programs for vulnerable customers due to the close relationship with their communities and customers.

Respectfully submitted,
/s/ Daniel Settlemyer

Daniel Settlemyer Policy
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January 26, 2021

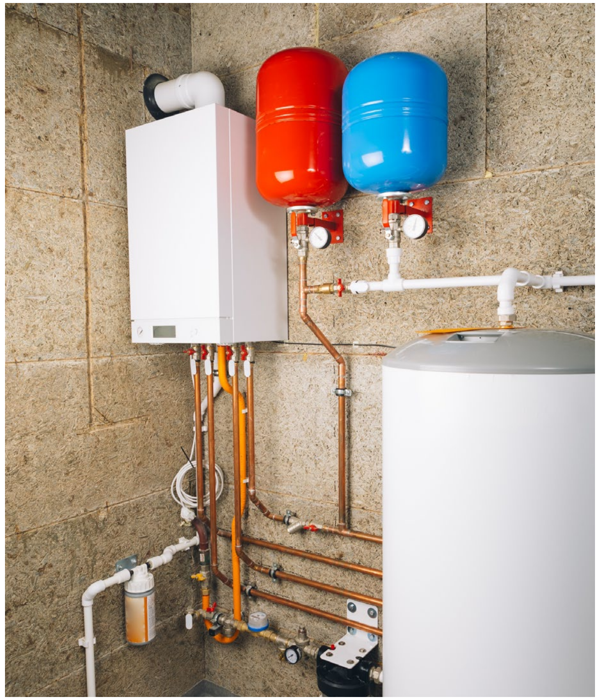
For a copy of this notice, please contact Daniel Settlemyer using the information contained above.

ATTACHMENT A

My community.
My choice.

January 2021

Scaling Up MCE's Energy Efficiency Programs



MCE’s Unique Role as an Energy Efficiency Program Administrator

- MCE is the only CCA that offers energy efficiency (EE) programs under the “apply to administer” pathway (PU Code 381.1(a)-(d))
    - Can serve all customer segments as defined in Business Plan
    - Same cost-effectiveness (CE) requirements as IOUs
- MCE began offering ratepayer-funded EE programs in 2012
- In May 2018, the CPUC approved MCE’s EE business plan for 2018-2025 with an annual budget of ~$10 million
- MCE EE portfolio consists of
    - Residential programs: single-family and multi-family
    - Non-residential programs: commercial, industrial and agricultural
    - Workforce, education and training program

Measure for Desired Outcomes

Challenge

EE portfolios are expected to fulfill multiple policy objectives in addition to the primary objective of reducing energy usage at the least cost possible. However, many of these policy objectives are not supported by a single cost-effectiveness metric.

EE Policy Objectives

- Save energy
- Reduce GHG emissions
- Enhance equity by serving low- and middle-income customers
- Undertake research and development of emerging technologies
- Conduct workforce training and education
- Advocate for better codes and standards

Policy Recommendation 1:

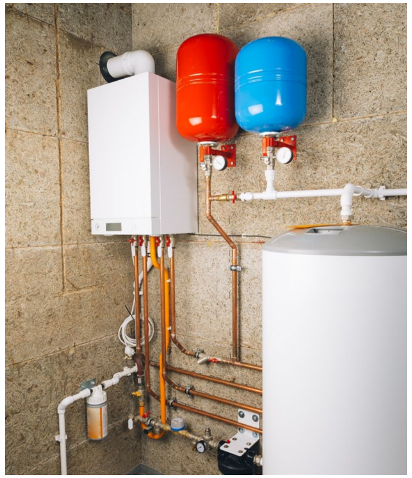
Split EE Portfolio into 3 Sub-Portfolios

Align EE programs with the State's policy objectives by dividing EE portfolios into three sub-portfolios. This will allow for better measurement of how each sub-portfolio contributes to its respective and distinct EE policy objectives.

Resource

Equity

Market Transformation



MCE

Benefits of Creating Sub-Portfolios

Resource Programs

Allows EE to compete on a level playing field as a supply side resource without the limitation of supporting the cost effectiveness of equity and market transformation programs. Increases the ability of resource programs to meet cost-effectiveness (CE) requirements:

- MCE's 2021 portfolio TRC would increase from 1.08 to 1.28
- MCE's 2021 portfolio PAC would increase from 1.17 to 1.48

Equity Programs

Program Administrators (PAs) can more effectively serve vulnerable customers because they would no longer be forced to choose between programs that serve vulnerable people and those that can be offered cost-effectively.

Market Transformation (MT) Programs

Allows MT initiatives to reach their full potential by allowing PAs to focus on getting the product or practice into code or standard with the expectation of CE over a longer time frame.

Policy Recommendation 2:

Resource Program Should Use the PAC

Use the Program Administrator Cost (PAC) test to calculate cost effectiveness of the EE portfolio. The PAC only considers costs and benefits incurred by the PA, not those incurred by the customer

$$\frac{PA\ Benefits}{PA\ Cost}$$

Currently, the Total Resource Cost (TRC) test is being used. It includes all costs of the EE resource (PA and participant costs) but only considers PA benefits, not participants benefits (e.g. non-energy benefits (NEBs))

$$\frac{PA\ Benefits}{PA\ Cost + Participant\ Cost}$$

Policy Recommendation 3:

Broaden Eligibility for Equity Programs

EE equity programs should be expanded from mainly targeting residential customers to also include certain non-residential customers (e.g. small and medium businesses (SMBs) and public sector buildings in disadvantaged and low-income communities)

- The CAEECC Underserved Working Group is developing definitions for these sectors

Policy Recommendation 4:

Cost Effectiveness for Equity Programs

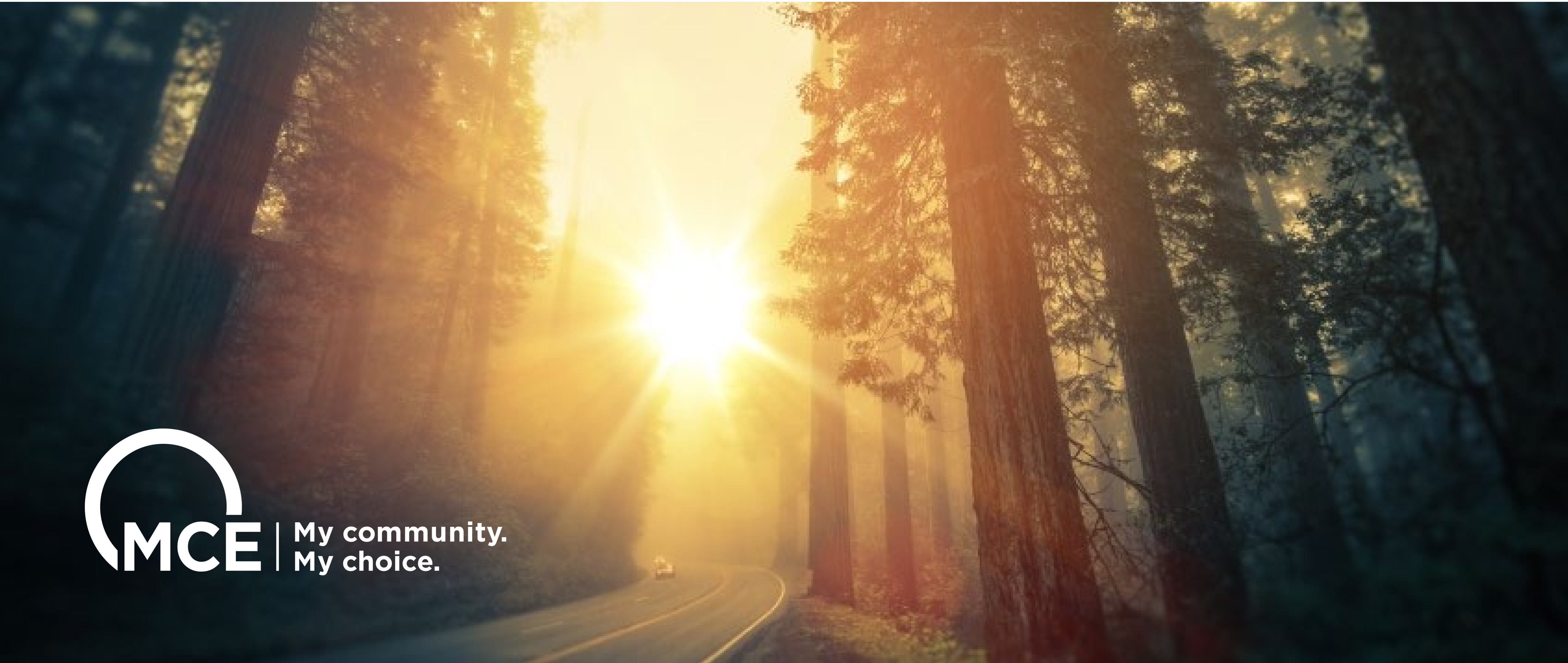
Non-Energy Benefits (NEBs) should be considered in the CE calculations for equity programs to appropriately value the contribution to certain policy objectives such as increased equity and workforce development

- NEB values and the process for incorporating them into the CE tool (CET) must be developed through a transparent stakeholder process
- The NEB framework must be consistent across all PAs to ensure accurate comparison of programs
- Build upon the CET being developed under the Energy Savings Assistance (ESA) program, the ESA-CET

MCE

Thank You!

Alice Havenar-Daughton
Director of Customer Programs
ahavenar-daughton@mcecleanenergy.org



**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

COMMENTS OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON THE PROPOSED DECISION

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January 28, 2021

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- ✓ Given the short time frame available, the final decision should establish a set list of available resources from which IOU procurement can be made for Summer 2021. These resources should include:

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  - o Any resource on the CAISO's most recent Announced Retirement and Mothball list; and

  - o Any resource not indicated on CAISO's Final NQC Report for Compliance Year 2021, including firm import energy contracts.

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  - o Limit procurement to that which is necessary for Summer 2021 only, and to contracts not to exceed one year except in extraordinary cases;

  - o Allocate the quantity procured among IOUs, based on their proportional load share;

  - o Keep the procurement obligation with the IOUs, separate from the RA program; and

  - o Limit prices paid for this procurement to the CPM short offer cap plus the summer penalty price.

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I. INTRODUCTION

In response to the Administrative Law Judge's December 11, 2020 (Email Ruling)[2] CalCCA provided recommendations to frame the proposed scope of a procurement order to

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address Summer 2021 and 2022 reliability needs.[3] Following the Email Ruling and the filing of responsive comments, the Commission issued the Proposed Decision on January 8, 2021. CalCCA appreciates the Commission's swift action to address potential reliability events. However, due to the compressed timeline, the Proposed Decision was issued in advance of full consideration of the parties' recommendations in their responses to the Email Ruling. CalCCA requests that the Commission schedule workshops to further assess need and adopt parameters to ensure the procurement is "right sized" and does not otherwise interfere with the operation of the existing resource adequacy (RA) market.

The Proposed Decision directs the investor-owned utilities (IOUs) to pursue one of the available strategies for addressing potential reliability events in the Summer of 2021, "incremental additional capacity procurement," on an accelerated timeframe.[4] Although the Proposed Decision directs the IOUs to begin procuring immediately, it merely lays out the "resource types" that may be considered for procurement, which include "[i]ncremental capacity from existing power plants through efficiency upgrades, revised power purchase agreements, etc.," "[c]ontracting for generation that is at-risk of retirement," and "[i]ncremental energy storage capacity."[5] The Proposed Decision does not provide specific guidance on how the IOUs should implement this directive, what resources are "incremental," what quantity of resources should be procured, or how this procurement should interact with other reliability-focused compliance requirements.

[3] 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, December 18, 2020.
[4] Proposed Decision at 9.
[5] Proposed Decision at 11.

The Proposed Decision thus lacks several critical details required for successful and cost-effective procurement to alleviate potential reliability events in Summer 2021 and 2022. A procurement regime lacking these details could result in market disruption, escalated capacity pricing, and even potential enforcement actions, without ever achieving the goal of increasing capacity available to CAISO.

CalCCA continues to stress the need for workshops in January 2021 to review and further develop the needs assessments already performed and the impact of the various sensitivities discussed in its testimony in this proceeding.[6] These workshops will develop guidance for implementing the decision, and more detailed orders for future procurement, particularly for Summer 2022. Given the lack of time available for these discussions prior to procurement for Summer 2021 reliability, and recognizing it is critical for the IOUs to begin their procurement immediately, CalCCA proposes revisions to the Proposed Decision to establish a specific set of available resources from which IOU procurement can be made. CalCCA also proposes revisions to establish limits and provide guidelines for IOUs implementing the procurement directive, to ensure the procurement is truly "incremental" to resources already contracted or expected to be contracted under existing RA obligations.

II. REFINE NEEDS ANALYSIS THROUGH WORKSHOPS

As noted, the Proposed Decision does not either specify a targeted amount, or provide gloss on what the Commission considers "incremental" for the purposes of the procurement ordered. CalCCA thus proposes workshops among stakeholders to educate and provide guidance as to: 1) what amount of procurement or target volume should be sought; and 2) what resources will be considered "incremental."

[6] Direct Testimony of Nicholas J. Pappas, Michael Hyams, Matthew Langer, Mahayla Slackerelli and Samantha Weaver on Behalf of California Community Choice Association (CalCCA (Pappas)), at 21.

CalCCA urges the Commission to clearly define and delineate resource eligibility at the outset. As an initial matter, the Commission, in coordination with the California Independent System Operator (CAISO) and other stakeholders, should clearly define the amount of "incremental" need that must be met. The determination of this amount is appropriate for stakeholder workshops to encourage discussion and review of available needs assessments and seek buy-in for a methodological approach to the issue going forward.

The Commission should then address what resources will be available for procurement under the decision. The Commission's ultimate goal of achieving an overall *increase* in contracted capacity must remain paramount. It is imperative that procurement under the Proposed Decision not disrupt or cannibalize available RA supply or exacerbate scarcity pricing. Workshops will help the Commission further develop the ideal amount of procurement, and more fully develop the concepts of "incremental" resources, and how they can be identified.

Given the time constraints applicable to procurement for Summer 2021, CalCCA appreciates that a full assessment may not be completed before procurement for that period commences. CalCCA thus proposes specific categories of resources for procurement for Summer 2021 procurement. This list is narrowly targeted to out-of-market resources that would not otherwise be procured by load serving entities (LSEs) for RA showings, and is structured to minimize disruption to LSE procurement for RA compliance.

A. Further Develop the Needs Assessment to Refine Target

An approach to a "target" for procurement must start with an accurate assessment of the existing fleet, planned new resources, and anticipated import RA. 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 assessment must fully recognize the value of non-RA demand response (DR) resources and contributions from behind-the-meter resources, and any other "out of market" secondary demand side resources. The assessment should also account for the estimated availability of emergency load reduction programs (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.

As CalCCA noted in its reply testimony,[7] the workshops should review and harmonize recent analyses performed by CAISO, Southern California Edison, Commission Staff, and any other stakeholders. A 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 ELRPs or other out-of-market programs.

B. Define Resource Eligibility for Summer 2021 Procurement

Recognizing there is not time for robust discussion of the total "incremental" need prior to procurement for Summer 2021, CalCCA proposes the Commission specifically identify resources that are subject to procurement for Summer 2021. To best ensure "incrementality," CalCCA suggests limiting immediate procurement to resources that are not otherwise available to LSEs to meet their 2021 monthly system RA requirements. Without this limitation, procurement under the final decision could severely disrupt load serving entity (LSE) RA procurement and cannibalize, rather than expand, available RA supply.

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[7] Reply Testimony of Nicholas J. Pappas on Behalf of California Community Choice Association at 7.

If, for example, an IOU were to seek to procure RA that is currently the subject of bilateral negotiations between a supplier and an LSE attempting to fulfill its Month Ahead Requirement, the IOU and LSE would be in competition for the same resource. The net result would be higher prices paid by whichever entity "won" the contract - with no net gain in overall system capacity. The only likely increases will be in LSE deficiencies, and the payment by all customers of scarcity pricing for RA products. Such outcomes would be counterproductive.

Resources procured centrally for Summer 2021 should therefore be very narrowly targeted to 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. The Commission's ultimate goal of achieving an overall *increase* in contracted capacity must remain paramount. CalCCA proposes that a new section 5.4 as set out in Attachment A be added to the final decision, requiring that initially, and until superseded by guidance developed in the workshops discussed above, resources within the scope of procurement include only the following as "incremental" resources:

- Resources that could increase their available NQC with limited physical, legal, or regulatory modifications. This will include any resource on CAISO's Final NQC Report for Compliance Year 2021 that:
    - 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 RA procurement due to other economic, legal, or regulatory reasons which require central procurement.
- Any resource on the CAISO's most recent Announced Retirement and Mothball list.[8]
- Any resource not indicated on CAISO's Final NQC Report for Compliance Year

[8] December 18, 2020 Announced Retirement and Mothball List http://www.caiso.com/Documents/AnnouncedRetirementAndMothballList.xlsx.

2021, including firm import energy contracts.

To facilitate expedient procurement, the Commission could use confidential data from RA showings and other sources to develop this list of known available, out-of-market resources which would be eligible based on the above criteria.

III. PROVIDE IMPLEMENTATION GUIDANCE AND PROCUREMENT PARAMETERS

In addition to the workshops and needs assessment discussed above, CalCCA proposes parameters for the procurement and implementation guidelines for the IOUs to follow in procurements under the final decision. CalCCA proposes section 5.4 include specific limitations to guide the ordered procurement. Section 5.4 will limit procurement under the decision as follows:

A. Limit Procurement to 2021 and Prioritize Short Term Procurement

Procurement under the final decision should be focused on Summer 2021 and exclude consideration of future procurement periods. The Proposed Decision was issued during a period of uncertainty in the RA markets, given the on-going review of the RA program including consideration of structural reform proposals. Most readily available capacity resources are already under contract, as many LSEs have already procured or are in the midst of procurements for two or three years forward. Thus, at least until guidelines are in place clearly identifying which resources are intended to be "incremental" and therefore subject to procurement under the decision, IOU procurement is likely to disrupt and confuse an already chaotic RA market.

As noted previously, CalCCA has highlighted certain sensitivities in the CAISO and SCE needs assessments. With respect to procurement for Summer 2022, there is ample time to review and consider these sensitivities, and to prepare a more precise and detailed needs assessment for that period. Furthermore, additional resources will be coming online after September 2021, so that the need during the Summer 2021 is likely to be transitory. To tailor procurement to the specific, imminent, period of need, and to avoid unnecessary disruption in the RA markets, short-term procurement should be prioritized. CalCCA proposes that procurement under the final decision be limited to contracts not to exceed one-year in length.

In the event that some procurement currently underway for the IRP Procurement Track may be expedited, such as new storage projects, it may be reasonable to approve a longer-term contract under a specific, transitional process. In this case, the resource could be removed from the LSE's (including bundled IOU's) D.19-11-016 portfolio for 2021, with costs recovered through this emergency procurement, prior to transitioning back to the LSE portfolio in 2022 and returning to use for compliance with D.19-11-016.

B. Allocate the Quantity Procured Among IOUs

The Proposed Decision does not specify the total amount of needed procurement or what each IOU should individually procure. In order to avoid excessive, costly, and potentially duplicative procurement, CalCCA urges the Commission to limit each IOU's procurement to no more than its proportional load share for its bundled customers and unbundled customers in its service territory.

C. Keep Emergency Procurement Separate from the RA Program for Compliance Purposes

CalCCA agrees with the framing of the procurement ordered by the Proposed Decision as a specific IOU-level requirement, and urges this obligation remain with the IOUs and not be subject to delegation or otherwise pushed down into individual LSE obligations. Specifically, this procurement should be considered incremental to individual LSE RA procurement and neither the compliance obligation nor the resource attributes should be allocated to LSEs, including IOU bundled portfolios, for the purposes of RA program accounting.

The IOUs' procurement obligation should be clarified to remain an IOU-level requirement that may not be delegated to individual LSEs. In other words, individual LSE obligations should remain at their current amounts, and any incremental need should be procured by the IOUs above that threshold.

D. Price Caps

Prices paid by the IOUs should be limited to the CPM soft offer cap plus the summer penalty price, except in the case of 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.

IV. CONCLUSION

CalCCA appreciates the opportunity to submit these comments and request adoption of the recommendations proposed herein. For all the foregoing reasons, the Commission should modify the Proposed Decision as provided in Attachment A.

Respectfully submitted,

Evelyn Kahl

EVELYN KAHL
General Counsel
California Community Choice Association

January 28, 2021

ATTACHMENT A
Proposed Changes to Proposed Decision

New Section 5.4

5.4. Specific Procurement Limitations

Until superseded by guidance developed in the workshops convened under this proceeding, or as otherwise ordered by the Commission, procurement under this decision shall be limited as follows:

1. Resources included within the scope of procurement shall include only the following as "incremental" resources:

A. Resources which could increase their available NQC with limited physical, legal, or regulatory modifications. This will include any resource on CAISO's Final NQC Report for Compliance Year 2021 that

i. Offers more capacity than its rated NQC;

ii. 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

iii. Can be clearly demonstrated to be "out of market" for LSE RA procurement due to other economic, legal, or regulatory reasons which require central procurement.

B. Any resource on the CAISO's most recent Announced Retirement and Mothball list.

C. Any resource not indicated on CAISO's Final NQC Report for Compliance Year 2021, including firm import energy contracts.

2. Procurement under this decision is limited to purchases of capacity and/or energy for delivery during the period May- September, 2021, and contracts entered into for such capacity and/or energy may not exceed one-year in length.

4. Each IOU's procurement under this decision shall be limited to no more than its proportional load share for its bundled customers and unbundled customers in its service territory.

5. Prices paid by the IOUs for procurement under this decision shall be limited to the CPM soft offer cap plus the summer penalty price. An IOU may seek Commission approval for contracts exceeding the CPM soft offer cap plus the summer penalty price, on a cost basis, if compelling circumstances justify extraordinary one-time fixed costs.

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CALIFORNIA COMMUNITY CHOICE ASSOCIATION
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As noted, the Proposed Decision does not either specify a targeted amount, or provide gloss on what the Commission considers "incremental" for the purposes of the procurement ordered. CalCCA thus proposes workshops among stakeholders to educate and provide guidance as to: 1) what amount of procurement or target volume should be sought; and 2) what resources will be considered "incremental."

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[6] Direct Testimony of Nicholas J. Pappas, Michael Hyams, Matthew Langer, Mahayla Slackerelli and Samantha Weaver on Behalf of California Community Choice Association (CalCCA (Pappas)), at 21.

CalCCA urges the Commission to clearly define and delineate resource eligibility at the outset. As an initial matter, the Commission, in coordination with the California Independent System Operator (CAISO) and other stakeholders, should clearly define the amount of "incremental" need that must be met. The determination of this amount is appropriate for stakeholder workshops to encourage discussion and review of available needs assessments and seek buy-in for a methodological approach to the issue going forward.

The Commission should then address what resources will be available for procurement under the decision. The Commission's ultimate goal of achieving an overall *increase* in contracted capacity must remain paramount. It is imperative that procurement under the Proposed Decision not disrupt or cannibalize available RA supply or exacerbate scarcity pricing. Workshops will help the Commission further develop the ideal amount of procurement, and more fully develop the concepts of "incremental" resources, and how they can be identified.

Given the time constraints applicable to procurement for Summer 2021, CalCCA appreciates that a full assessment may not be completed before procurement for that period commences. CalCCA thus proposes specific categories of resources for procurement for Summer 2021 procurement. This list is narrowly targeted to out-of-market resources that would not otherwise be procured by load serving entities (LSEs) for RA showings, and is structured to minimize disruption to LSE procurement for RA compliance.

A. Further Develop the Needs Assessment to Refine Target

An approach to a "target" for procurement must start with an accurate assessment of the existing fleet, planned new resources, and anticipated import RA. 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 assessment must fully recognize the value of non-RA demand response (DR) resources and contributions from behind-the-meter resources, and any other "out of market" secondary demand side resources. The assessment should also account for the estimated availability of emergency load reduction programs (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.

As CalCCA noted in its reply testimony,[7] the workshops should review and harmonize recent analyses performed by CAISO, Southern California Edison, Commission Staff, and any other stakeholders. A 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 ELRPs or other out-of-market programs.

B. Define Resource Eligibility for Summer 2021 Procurement

Recognizing there is not time for robust discussion of the total "incremental" need prior to procurement for Summer 2021, CalCCA proposes the Commission specifically identify resources that are subject to procurement for Summer 2021. To best ensure "incrementality," CalCCA suggests limiting immediate procurement to resources that are not otherwise available to LSEs to meet their 2021 monthly system RA requirements. Without this limitation, procurement under the final decision could severely disrupt load serving entity (LSE) RA procurement and cannibalize, rather than expand, available RA supply.

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[7] Reply Testimony of Nicholas J. Pappas on Behalf of California Community Choice Association at 7.

If, for example, an IOU were to seek to procure RA that is currently the subject of bilateral negotiations between a supplier and an LSE attempting to fulfill its Month Ahead Requirement, the IOU and LSE would be in competition for the same resource. The net result would be higher prices paid by whichever entity "won" the contract - with no net gain in overall system capacity. The only likely increases will be in LSE deficiencies, and the payment by all customers of scarcity pricing for RA products. Such outcomes would be counterproductive.

Resources procured centrally for Summer 2021 should therefore be very narrowly targeted to 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. The Commission's ultimate goal of achieving an overall *increase* in contracted capacity must remain paramount. CalCCA proposes that a new section 5.4 as set out in Attachment A be added to the final decision, requiring that initially, and until superseded by guidance developed in the workshops discussed above, resources within the scope of procurement include only the following as "incremental" resources:

- Resources that could increase their available NQC with limited physical, legal, or regulatory modifications. This will include any resource on CAISO's Final NQC Report for Compliance Year 2021 that:
    - 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 RA procurement due to other economic, legal, or regulatory reasons which require central procurement.
- Any resource on the CAISO's most recent Announced Retirement and Mothball list.[8]
- Any resource not indicated on CAISO's Final NQC Report for Compliance Year

[8] December 18, 2020 Announced Retirement and Mothball List http://www.caiso.com/Documents/AnnouncedRetirementAndMothballList.xlsx.

2021, including firm import energy contracts.

To facilitate expedient procurement, the Commission could use confidential data from RA showings and other sources to develop this list of known available, out-of-market resources which would be eligible based on the above criteria.

III. PROVIDE IMPLEMENTATION GUIDANCE AND PROCUREMENT PARAMETERS

In addition to the workshops and needs assessment discussed above, CalCCA proposes parameters for the procurement and implementation guidelines for the IOUs to follow in procurements under the final decision. CalCCA proposes section 5.4 include specific limitations to guide the ordered procurement. Section 5.4 will limit procurement under the decision as follows:

A. Limit Procurement to 2021 and Prioritize Short Term Procurement

Procurement under the final decision should be focused on Summer 2021 and exclude consideration of future procurement periods. The Proposed Decision was issued during a period of uncertainty in the RA markets, given the on-going review of the RA program including consideration of structural reform proposals. Most readily available capacity resources are already under contract, as many LSEs have already procured or are in the midst of procurements for two or three years forward. Thus, at least until guidelines are in place clearly identifying which resources are intended to be "incremental" and therefore subject to procurement under the decision, IOU procurement is likely to disrupt and confuse an already chaotic RA market.

As noted previously, CalCCA has highlighted certain sensitivities in the CAISO and SCE needs assessments. With respect to procurement for Summer 2022, there is ample time to review and consider these sensitivities, and to prepare a more precise and detailed needs assessment for that period. Furthermore, additional resources will be coming online after September 2021, so that the need during the Summer 2021 is likely to be transitory. To tailor procurement to the specific, imminent, period of need, and to avoid unnecessary disruption in the RA markets, short-term procurement should be prioritized. CalCCA proposes that procurement under the final decision be limited to contracts not to exceed one-year in length.

In the event that some procurement currently underway for the IRP Procurement Track may be expedited, such as new storage projects, it may be reasonable to approve a longer-term contract under a specific, transitional process. In this case, the resource could be removed from the LSE's (including bundled IOU's) D.19-11-016 portfolio for 2021, with costs recovered through this emergency procurement, prior to transitioning back to the LSE portfolio in 2022 and returning to use for compliance with D.19-11-016.

B. Allocate the Quantity Procured Among IOUs

The Proposed Decision does not specify the total amount of needed procurement or what each IOU should individually procure. In order to avoid excessive, costly, and potentially duplicative procurement, CalCCA urges the Commission to limit each IOU's procurement to no more than its proportional load share for its bundled customers and unbundled customers in its service territory.

C. Keep Emergency Procurement Separate from the RA Program for Compliance Purposes

CalCCA agrees with the framing of the procurement ordered by the Proposed Decision as a specific IOU-level requirement, and urges this obligation remain with the IOUs and not be subject to delegation or otherwise pushed down into individual LSE obligations. Specifically, this procurement should be considered incremental to individual LSE RA procurement and neither the compliance obligation nor the resource attributes should be allocated to LSEs, including IOU bundled portfolios, for the purposes of RA program accounting.

The IOUs' procurement obligation should be clarified to remain an IOU-level requirement that may not be delegated to individual LSEs. In other words, individual LSE obligations should remain at their current amounts, and any incremental need should be procured by the IOUs above that threshold.

D. Price Caps

Prices paid by the IOUs should be limited to the CPM soft offer cap plus the summer penalty price, except in the case of 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.

IV. CONCLUSION

CalCCA appreciates the opportunity to submit these comments and request adoption of the recommendations proposed herein. For all the foregoing reasons, the Commission should modify the Proposed Decision as provided in Attachment A.

Respectfully submitted,

Evelyn Kahl

EVELYN KAHL
General Counsel
California Community Choice Association

January 28, 2021

ATTACHMENT A
Proposed Changes to Proposed Decision

New Section 5.4

5.4. Specific Procurement Limitations

Until superseded by guidance developed in the workshops convened under this proceeding, or as otherwise ordered by the Commission, procurement under this decision shall be limited as follows:

1. Resources included within the scope of procurement shall include only the following as "incremental" resources:

A. Resources which could increase their available NQC with limited physical, legal, or regulatory modifications. This will include any resource on CAISO's Final NQC Report for Compliance Year 2021 that

i. Offers more capacity than its rated NQC;

ii. 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

iii. Can be clearly demonstrated to be "out of market" for LSE RA procurement due to other economic, legal, or regulatory reasons which require central procurement.

B. Any resource on the CAISO's most recent Announced Retirement and Mothball list.

C. Any resource not indicated on CAISO's Final NQC Report for Compliance Year 2021, including firm import energy contracts.

2. Procurement under this decision is limited to purchases of capacity and/or energy for delivery during the period May- September, 2021, and contracts entered into for such capacity and/or energy may not exceed one-year in length.

4. Each IOU's procurement under this decision shall be limited to no more than its proportional load share for its bundled customers and unbundled customers in its service territory.

5. Prices paid by the IOUs for procurement under this decision shall be limited to the CPM soft offer cap plus the summer penalty price. An IOU may seek Commission approval for contracts exceeding the CPM soft offer cap plus the summer penalty price, on a cost basis, if compelling circumstances justify extraordinary one-time fixed costs.

February 1, 2021

California Public Utilities Commission
Energy Division
Attention: Tariff Unit
505 Van Ness Avenue, 4th Floor
San Francisco, CA 94102-3298

MCE Advice Letter 47-E

RE: 2022 Budget Request and Marketing, Education and Outreach Plan for the Disadvantaged Communities Green Tariff and the Community Solar Green Tariff Programs

Pursuant to Ordering Paragraph ("OP") 2 and 4 of Resolution E-4999,[1] Marin Clean Energy ("MCE") hereby submits this Tier 1 Advice Letter ("AL") to submit the program budget request and marketing, education and outreach ("ME&O") plan for the Disadvantaged Communities Green Tariff ("DAC-GT") and Community Solar Green Tariff ("CS-GT") programs for the program year ("PY") 2022.

TIER DESIGNATION

This AL has a Tier 1 designation pursuant to OP 2 of Resolution E-4999.

EFFECTIVE DATE

MCE requests that this Tier 1 AL become effective upon date of submittal, which is February 1, 2021.

BACKGROUND

On June 21, 2018, the California Public Utilities Commission ("Commission" or "CPUC") approved D.18-06-027, adopting two new community solar programs to promote the use of renewable generation among residential customers in disadvantaged communities ("DACs"),[2] as directed by the California Legislature in Assembly Bill ("AB") 327 (Perea), Stats. 2013, ch 611. The DAC-GT and the CS-GT programs offer 100% solar energy to eligible customers and provide

[1] OP 2 and 4 of Resolution E-4999 specifically directed Pacific Gas and Electric Company, Southern California Edison and San Diego Gas & Electric Company to submit annual program budget estimates and ME&O plans to the Commission by February 1 of each year. While the CCA Implementation Advice Letters for the DAC-GT and CS-GT programs are still pending with the Commission, MCE assumes that it must follow the same requirements regarding the budget request approval as the investor-owned utilities.

[2] 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.

a 20% discount on the electric portion of the bill.

Pursuant to OP 17 of 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").[3] On May 7, 2020, MCE filed its Implementation AL for the DAC-GT and CS-GT programs with the Commission in MCE AL 42-E. At the time of writing of this AL, the approval of MCE's Implementation AL is still pending at the Commission.

On June 3, 2019, the Commission issued Resolution E-4999, which approved, with modification, the investor-owned utilities' ("IOUs") DAC-GT and CS-GT Implementation ALs. OP 2 of that Resolution directs the IOUs to submit a program budget requests and ME&O plan for the upcoming PY by February 1st of each year. The Resolution also provides details regarding the budget submission requirements and process. Furthermore, OP 4 of Resolution E-4999 specifies that Program Administrators must reconcile prior year budget forecasts and expenditures in their annual budget requests.

While Resolution E-4999 specifically directs the IOUs to submit annual program budget requests and ME&O plans, MCE assumes that this requirement equally applies to CCAs as Program Administrators of the DAC-GT and CS-GT programs. The submission and approval of this budget AL is the pre-requisite of having the DAC-GT and CS-GT budgets included in the Energy Resource Recovery Account ("ERRA") Forecast in June each year. The ERRA Forecast in turn enables cost recovery under the programs. Therefore, MCE is submitting this cover letter to ensure timely cost recovery for its programs.

PURPOSE

MCE hereby submits the budget request for PY 2022 for the DAC-GT and CS-GT programs. Per Resolution E-4999, the budget request covers the budget reconciliation for the previous PY (i.e., PY 2020) and the budget forecast for the upcoming PY (i.e., PY 2022). MCE requests a total budget of $1,456,113 for the DAC-GT and CS-GT programs for the PY 2022. Additional details can be found in Appendix A.

Once the Commission approves MCE's budget request, PG&E will be responsible for including the total budget request for MCE's DAC-GT and CS-GT programs in the 2022 ERRA Forecast filing due in early June of 2021. 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 as determined in the Resolution approving MCE's Implementation AL 42-E.[4]

In addition to the budget request, MCE submits its ME&O plan for PY 2022 as Appendix B.

CONCLUSION

MCE respectfully requests the Commission approve the budgets proposed herein and direct PG&E

[3] D.18-06-027, at p.104 (OP 17).
[4] At the time of writing of this AL, MCE AL 42-E is still pending with the Commission.

to transfer funds sufficient to meet MCE's approved annual budgets per the funding mechanisms discussed above.

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

*****Due to the COVID-19 pandemic and the shelter-at-home orders, MCE is currently unable to receive protests or responses to this advice letter via U.S. Mail or fax. Please submit protests or responses to this advice letter to EDTariffUnit@cpuc.ca.gov and jkopyciok-lande@mcecleanenergy.org*****

Anyone wishing to protest this advice letter filing may do so by letter via U.S. Mail, facsimile, or electronically, any of which must be received no later than 20 days after the date of this advice filing. Protests must be submitted to:

CPUC, Energy Division
Attention: Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102
Email: EDTariffUnit@cpuc.ca.gov

Copies should also be mailed to the attention of the Deputy Executive Director, Energy Division, Room 4004 (same address above).

In addition, protests and all other correspondence regarding this advice letter shall be sent by letter or transmitted electronically to the attention of:

Jana Kopyciok-Lande
Senior Policy Analyst
Marin Clean Energy
1125 Tamalpais Ave
San Rafael, CA 94901
Email: jkopyciok-lande@mcecleanenergy.org

There are no restrictions on who may file a protest, but the protest shall set forth specifically the grounds upon which it is based and shall be submitted expeditiously.

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

ADVICE LETTER SUMMARY

ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No.: Marin Clean Energy

Utility type:
- ☑ 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) #: 47

Tier Designation: 1

Subject of AL: Marin Clean Energy Budget Request and Marketing, Education and Outreach Plan for the Disadvantaged Communities Green Tariff and the Community Solar Green Tariff Programs

Keywords (choose from CPUC listing): Compliance, Solar

AL Type: ☐ Monthly ☐ Quarterly ☐ Annual ☑ One-Time ☐ Other:

If AL submitted in compliance with a Commission order, indicate relevant Decision/Resolution #:
Decision18-06-027, Resolution E-4999

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL: N/A

Summarize differences between the AL and the prior withdrawn or rejected AL: N/A

Confidential treatment requested? ☐ Yes ☑ No

If yes, specification of confidential information: N/A
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: N/A

Resolution required? ☐ Yes ☑ No

Requested effective date: 2/1/21

No. of tariff sheets:

Estimated system annual revenue effect (%):

Estimated system average rate effect (%):

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:

Service affected and changes proposed[1]:

Pending advice letters that revise the same tariff sheets: N/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
City: San Rafael
State: California Zip: 94901
Telephone (xxx) xxx-xxxx: 415-464-6044
Facsimile (xxx) xxx-xxxx:
Email: jkopyciok-lande@mcecleanenergy.org

Name:
Title:
Utility Name:
Address:
City:
State: District of Columbia Zip:
Telephone (xxx) xxx-xxxx:
Facsimile (xxx) xxx-xxxx:
Email:

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

Budget Forecast for the Disadvantaged Communities Green Tariff and Community Solar Green Tariff Programs for the Program Year 2022

Proposed by Marin Clean Energy

Heather Shepard
Director of Public Affairs
Marin Clean Energy
1125 Tamalpais Ave
San Rafael, CA 94901
E-mail: hshepard@mcecleanenergy.org

February 1, 2021

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Table of Figures

1. BACKGROUND

Per Resolution E-4999, annual program budgets must be presented by program and include the following budget line items:[1]

1. Generation cost delta, if any;[2]
2. 20 percent bill discount for participating customers (generation portion);
3. Program administration costs:
    a. Program management;
    b. Information technology (IT);
    c. Billing operations;
    d. Regulatory compliance; and
    e. Procurement.
4. Marketing, education and outreach (ME&O) costs:
    a. Labor costs;
    b. Outreach and material costs;
    c. Local CBO/ sponsor costs (for CS-GT only);

In addition to budget reconciliation and forecast, annual program budget submissions also include details on program capacity and customer enrollment numbers for both programs. More specifically, MCE reports on:

1. Existing capacity at previous PY's 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 the California Public Utilities Commission (CPUC or Commission) Energy Division staff directly:

1. Calculation of the generation cost delta;
2. Calculation of the 20% bill discount to participating customers;

2. BUDGET FORECAST FOR PY 2022

For PY 2022, MCE requests a total budget of $1,916,303 for the DAC-GT and CS-GT programs. A detailed budget forecast for each program by budget line item can be found in the table below.

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[1] A detailed description of each budget line item can be found in MCE's Implementation Plan, submitted in Appendix A to MCE Advice Letter 42-E filed on May 7, 2020.

[2] 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".

Table 1: MCE Budget Forecast for PY 2022

Tab	Category	DAC-GT	CS-GT	
1	Generation Cost Delta	$ 1,118,784	$ -	
2	20% Bill Discount	$ 232,258	$ -	
	Program Administration			
3a	Program Management	$ 101,250	$ 136,950	
3b	Information Technology	$ 23,224	$ 23,224	
3c	Billing Operations	$ 37,342	$ 10,308	
3d	Regulatory Compliance	$ 14,280	$ 14,280	
3e	Procurement	$ 18,235	$ 31,682	
	Subtotal Program Administration	**$ 194,331**	**$ 216,444**	
	Marketing, Education & Outreach			
4a	Labor Costs	$ 18,445	$ 54,740	
4b	Outreach and Material Costs	$ 2,800	$ 53,500	
4c	Local CBO/ Sponsor Costs	$ -	$ 25,000	
	Subtotal ME&O	**$ 21,245**	**$ 133,240**	
Total		**$ 1,566,618**	**$ 349,684**	**$ 1,916,303**

MCE provides the following clarifying notes regarding the budget summary.

Generation Cost Delta

MCE does not anticipate having *new* DAC-GT or CS-GT projects come online in 2022 due to the need for soliciting such projects. However, for the DAC-GT program, MCE will use an interim project while new projects are being solicited and built. Hence, the generation cost delta budget forecast for the DAC-GT program is based on the cost of the interim resource selected. More detail is provided in Appendix A to MCE Advice Letter (AL) 42-E.

20 Percent Bill Discount

As described in more detail in MCE AL 42-E, MCE proposes to only calculate the 20% discount for the generation portion of the electric bill.[3] The respective utility (in MCE's case PG&E) would be responsible for calculating the 20% discount on the delivery portion of the bill for CCA program participants. MCE only expects to have customers enrolled in the DAC-GT program in PY 2022. Customer enrollment for the CS-GT program is expected to begin in January 2023.

Program Administration Costs

Program management includes program development and management, budgeting, and reporting. IT costs include the costs to develop program tools and updating existing systems to accommodate program enrollment and billing. At this point in time, MCE expects the majority of IT costs to occur in 2022 to accommodate for the roll-out of the hybrid billing methodology in late 2022 or

[3] At the time of filing of this 2021 Budget Advice Letter, the approval of MCE's Implementation AL 42-E is still pending with the Commission.

early 2023.

Billing operations covers costs for ongoing billing operations and customer support once all systems are developed. Regulatory covers costs for regulatory compliance and related program filings with the Commission. Procurement covers the costs to develop and manage the solicitations for solar resources under the program, as well as annual renewable energy credit (REC) retirement and compliance functions.

Marketing, Education and Outreach (ME&O)
ME&O budgets are split in three categories – (1) MCE labor costs; (2) MCE direct costs for outreach and material; and (3) funds provided to the local CBOs who function as the sponsor for the CS-GT program.

3. BUDGET CAPS

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.[4] However, administrative and ME&O costs may be higher than these budget allocations in the first two years of program implementation (i.e., PYs 2021 and 2022 for MCE), acknowledging that program start-up costs may be higher. Hence, MCE will only include information on budget caps in subsequent submissions of the Annual Budget Advice Letter.

4. BUDGET RECONCILIATION FOR PY 2020

MCE submitted a budget forecast for PY 2020 as an attachment to its Implementation AL 42-E which was filed with the Commission on May 7, 2020. Due to delays in the AL approval process, MCE did not launch the DAC-GT and CS-GT programs in 2020 as originally expected. Hence, MCE is reconciling all forecasted program costs from 2020 in this budget advice letter. MCE is now considering 2021 to be its first program year. The table below shows the forecasted costs for PY 2020 per budget line item that will be carried forward to future program years.

[4] Resolution E-4999 determined that Program Administrators can submit a Tier 3 Advice Letter requesting an adjustment to the budget allocations if the need arises. See Resolution E-4999 at p.27.

Table 2: MCE Budget Reconciliation for PY 2020

Tab	Category	DAC-GT			CS-GT		
		Forecast	Actual	**True-up**	Forecast	Actual	**True-up**
1	Generation Cost Delta	$ 36,199	$ -	**$ 36,199**	$ -	$ -	**$ -**
2	20% Bill Discount	$ 7,564	$ -	**$ 7,564**	$ -	$ -	**$ -**
	Program Administration						
3a	Program Management	$ 118,820	$ -	**$ 118,820**	$ 89,420	$ -	**$ 89,420**
3b	Information Technology	$ 24,814	$ -	**$ 24,814**	$ 24,814	$ -	**$ 24,814**
3c	Billing Operations	$ 23,180	$ -	**$ 23,180**	$ 5,970	$ -	**$ 5,970**
3d	Regulatory Compliance	$ 11,760	$ -	**$ 11,760**	$ 11,760	$ -	**$ 11,760**
3e	Procurement	$ 20,295	$ -	**$ 20,295**	$ 34,995	$ -	**$ 34,995**
	Subtotal Program Administration	**$ 198,869**	**$ -**	**$ 198,869**	**$ 166,959**	**$ -**	**$ 166,959**
	Marketing, Education & Outreach						
4a	Labor Costs	$ 21,560	$ -	**$ 21,560**	$ 5,390	$ -	**$ 5,390**
4b	Outreach and Material Costs	$ 5,650	$ -	**$ 5,650**	$ 3,000	$ -	**$ 3,000**
4c	Local CBO/ Sponsor Costs	$ -	$ -	**$ -**	$ 15,000	$ -	**$ 15,000**
	Subtotal ME&O	**$ 27,210**	**$ -**	**$ 27,210**	**$ 23,390**	**$ -**	**$ 23,390**
Total		**$ 269,841**	**$ -**	**$ 269,841**	**$ 190,349**	**$ -**	**$ 190,349**

5. 2022 BUDGET REQUEST

Based on the budget forecast for PY 2022 presented in section 2 and the budget reconciliation for PY 2020 presented in section 4, MCE is requesting a total budget of $1,456,113 for the DAC-GT and CS-GT programs in this budget AL.

Table 3: MCE Budget Request for PY 2022

	DAC-GT	CS-GT	Total
Budget Carry-over from PY 2020	$ 269,841	$ 190,349	**$ 460,190**
Budget Request for PY 2022	$ 1,566,618	$ 349,684	**$ 1,916,303**
TOTAL	**$1,296,777**	**$ 159,336**	**$1,456,113**

6. PROGRAM CAPACITY AND ENROLLMENT NUMBERS

MCE reports forecasted program capacity and customer enrollment numbers for PY 2022 in the table below. MCE is unable to report on existing program capacity and customer enrollment numbers to date as the programs have not launched yet.

MCE is only reporting estimated program capacity and enrollment numbers for the DAC-GT program, as this program is expected to be served by an interim solar resource in MCE's portfolio while new resources are being procured specifically for the program. For the CS-GT program, MCE will procure new solar resources that are only expected to come online in 2023.

Table 4: Program Capacity and Enrollment Count for DAC-GT for PY 2022

Category	DAC-GT	CS-GT
Estimated capacity to be procured (MW)	4.646	1.2825
Estimated customer enrollment (#)	2303	0

APPENDIX B

Marketing, Education and Outreach Plan for the Disadvantaged Communities Green Tariff and Community Solar Green Tariff Programs for Program Year 2022

Proposed by Marin Clean Energy

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February 1, 2021

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1. PURPOSE AND GOALS

MCE will develop and implement a targeted customer marketing, education, and outreach (ME&O) campaign under the Disadvantaged Communities Green Tariff (DAC-GT) and Community Solar Green Tariff (CS-GT) programs to ensure potential customers in disadvantaged communities (DACs) are aware of the opportunity to benefit from the programs.

MCE will develop and implement separate targeted customer marketing, education, and outreach (ME&O) campaigns for the DAC-GT and CS-GT programs due to the differing enrollment processes of the two programs. Eligible customers for DAC-GT will be identified and automatically enrolled in the program by MCE. Hence, no customer recruitment for program participation is required. Eligible customers for CS-GT will not be automatically enrolled in the program; instead will be required to opt their accounts into the program by completing an enrollment form.

MCE's ME&O strategy for the DAC-GT program has three main goals:

1. Notify DAC-GT customers that their account has been automatically enrolled in the program;

2. Provide information (i.e., FAQs) about the program;

3. Increase customer awareness of energy use, savings opportunities, other customer incentives, rate options (i.e. TOU), discounts, or programs.

The main goals of the CS-GT ME&O strategy are:

4. Enroll eligible customers in the CS-GT program;

5. Increase awareness of, and enrollment in, California Alternate Rates for Energy (CARE) and Family Electric Rate Assistance (FERA) programs;

6. Increase customer awareness of energy use, savings opportunities, other customer incentives, rate options (i.e. TOU), discounts, or programs;

7. Address barriers to program participation and leverage best practices to participation and ensure that outreach to DAC and hard-to-reach customers is accessible and equitable.

For both ME&O campaigns, MCE aims to achieve meaningful and diverse customer engagement through a culturally-competent, multilingual approach. For CS-GT, MCE will develop a targeted customer engagement campaign that leverages community-based marketing best practices such as:

- A mix of multilingual and culturally-competent communications including community advertising (e.g., banners, newsprint), geo-targeted digital ads, and direct mail, and

- Direct customer outreach and partnerships with community-based organizations (CBOs) and local government agencies.

Ultimately, MCE will measure ME&O program success for the CS-GT program by the number of customers enrolled in the program. We will also measure program success by the overall number of customers reached, and the diversity of customers reached.

The following subsections provide additional details about MCE's ME&O approach for the DAC-GT and CS-GT programs.

2. GUIDING PRINCIPLES

MCE is committed to developing diverse and culturally appropriate communication strategies to ensure that stakeholders can participate in decisions and actions that impact their communities. As such, MCE commits to the following guiding principles throughout the ME&O engagement process for the DAC-GT and CS-GT programs. MCE aims to:

- Achieve diverse and meaningful engagement that reflects the demographics of DAC communities to ensure equitable outreach across race, income and age barriers;
- Maintain transparency and accessibility of information by bringing the information directly to customers in their neighborhood, their community, or interest space to better engage them in the process;
- Build a collaborative process with community partners to ensure barriers and benefits to participation are considered in the ME&O activities to the maximum extent possible.

3. TARGET AUDIENCE

For the DAC-GT 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. 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 (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)[1]

If there is not enough program capacity to enroll all customers in each category under the DAC-GT program, customers from the respective category will be randomly selected for program enrollment. MCE will monitor program attrition on a monthly basis and enroll additional customers from the waitlist as appropriate.

[1] MCE has the capacity to serve approximately 2303 customers under the DAC-GT program, based on an allocated program capacity of 4.646MW.

The following table shows the list of eligible census tracts for DAC-GT auto-enrollment.

Figure 1. Qualifying Neighborhoods in MCE Service Territory for DAC-GT Auto-enrollment

90% Cal Enviroscreen Score			
Census Tract	**California County**	**ZIP**	**Nearby City (to help approximate location only)**
6013379000	Contra Costa	94804	Richmond
6013312000	Contra Costa	94565	Pittsburg
6013365002	Contra Costa	94801	Richmond
6013377000	Contra Costa	94801	Richmond

For the CS-GT program, the primary target audience for the ME&O strategy are existing and eligible CARE/FERA customers living in top 25% DAC communities statewide per CalEnviroscreen. In MCE's service area, DAC communities include customers in the following neighborhoods:

Figure 2. Qualifying Neighborhoods in MCE Service Territory for CS-GT

Census Tract	Nearby City (to help approximate location only)	ZIP	California County
6013305000	Antioch	94509	Contra Costa
6013320001	Martinez	94553	Contra Costa
6013302005	Oakley	94561	Contra Costa
6013312000	Pittsburg	94565	Contra Costa
6013310000	Pittsburg	94565	Contra Costa
6013311000	Pittsburg	94565	Contra Costa
6013314103	Pittsburg	94565	Contra Costa
6013314104	Pittsburg	94565	Contra Costa
6013313102	Pittsburg	94565	Contra Costa
6013309000	Pittsburg	94565	Contra Costa
6013313101	Pittsburg	94565	Contra Costa
6013379000	Richmond	94804	Contra Costa
6013365002	Richmond	94801	Contra Costa
6013377000	Richmond	94801	Contra Costa
6013382000	Richmond	94804	Contra Costa
6013376000	Richmond	94801	Contra Costa
6013380000	Richmond	94804	Contra Costa
6013375000	Richmond	94801	Contra Costa
6013381000	Richmond	94804	Contra Costa
6013358000	Rodeo	94572	Contra Costa
6013368002	San Pablo	94806	Contra Costa
6013366002	San Pablo	94806	Contra Costa
6013368001	San Pablo	94806	Contra Costa
6013364002	San Pablo	94806	Contra Costa
6013392200	San Pablo	94806	Contra Costa
6095250701	Vallejo	94590	Solano
6095250801	Vallejo	94592	Solano
6095250900	Vallejo	94590	Solano
6095251802	Vallejo	94589	Solano
6095251901	Vallejo	94589	Solano

4. ME&O TACTICS AND STRATEGIES

4.1. Communications and Media Content

A variety of communications and media content will be developed to promote the programs, including flyers and fact sheets, as well as content on MCE's website. This material will be translated and improved throughout the ME&O strategy via message testing to ensure it is culturally competent and effective. Additionally, for the CS-GT program, MCE will run social media campaigns, as well as print and digital advertisements, in multiple languages to encourage program enrollment. Direct mailing and email blasts will also be utilized to target customers.

4.2. Community Outreach

To meet our ME&O goals, MCE will develop an outreach and engagement strategy leveraging the key community outreach tactics summarized below. The community outreach strategy will include a multilingual and culturally competent approach to engagement and consider the specific needs of DAC communities in MCE's service area. CS-GT outreach will be informed by data (census tracks, 4013, etc.) in order to identify customers who are most likely to enroll in the programs.

4.2.1. Grassroots Outreach

MCE will conduct grassroots outreach to engage directly with community members at community events. MCE already regularly attends and sponsors many community events throughout its service area, including neighborhood festivals, farmers markets, holiday celebrations, and special events. Under the community outreach strategy for the CS-GT programs, MCE will focus on expanding the breadth of events attended in DAC neighborhoods.

MCE will utilize the expertise of community leaders to identify impactful events and will offer workshops and webinars as appropriate. As community events and workshops are held, we will closely track the diversity in race, age and income of participants, to ensure that participation reflects census distribution demographics of the DAC communities. Additionally, we will maximize convenience of meetings and events to public transportation, and ensure events are ADA accessible.

Due to COVID-19, appropriate considerations will be made for MCE attendance at in-person events. When possible, in person community outreach will be replaced with virtual workshops, webinars and digital toolkits.

4.2.2. Partnerships with Community Based Organizations

Partnering with Community Based Organizations (CBOs) is a critical facet of MCE's ME&O plan. CBOs have intimate knowledge of the local communities they serve and will serve as valuable resources for how best to conduct outreach that makes sense for members of their communities. As MCE engages with CBO partners, we seek to establish open dialogue, build awareness and understanding among community members, identify community-specific issues, and develop methods for disseminating relevant information. For example, CBOs will help coordinate program-specific workshops to disseminate program information to their constituencies. MCE will provide funding for CBOs to conduct outreach for the CS-GT program.

Additionally, many other local City departments already conduct outreach in the same communities in which we will conduct program outreach. MCE will investigate and pursue opportunities to collaborate as appropriate.

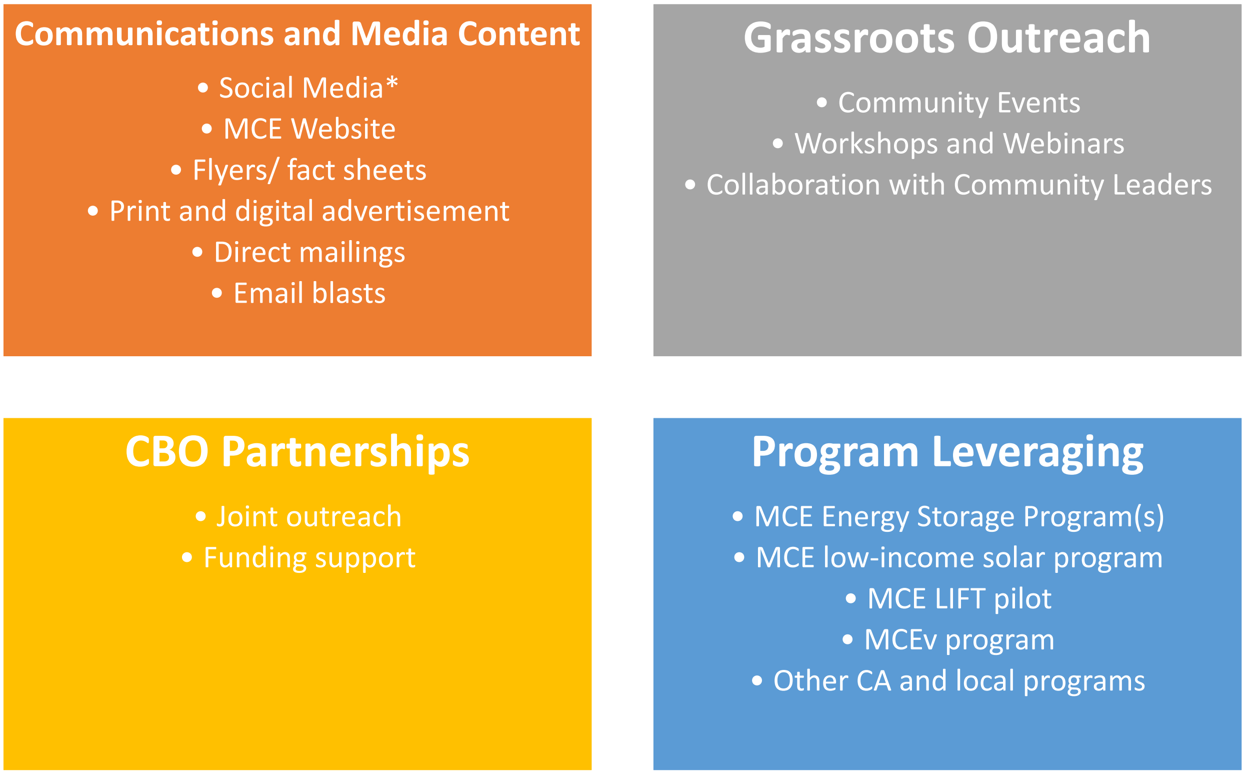
4.3. Program Leveraging

California offers a plethora of clean energy, energy efficiency, and energy storage programs, with several of them targeting income-qualified customers or customers in DACs. Complementing the state's programs, MCE also has developed a wide range of in-house program offerings with many of them focusing on vulnerable customers. MCE's Single Point of Contact (SPOC) model provides "behind-the-scene" coordination with various programs and funding sources in order to provide MCE's customers with the comprehensive, streamlined "one-stop-shop" guidance they need to navigate and enroll in these different offerings, maximizing the benefit to the customers while interweaving the value of all leveraged programs.

Under the DAC-GT/CS-GT ME&O plan, MCE will leverage its relationships and interactions with customers through existing programs to inform, educate and encourage program participation through its SPOC model. For example, MCE will leverage the following programs for joint outreach efforts: MCE's newly developed Battery Energy Storage Programs, MCE's low-income solar program for homeowners, MCE's Low-Income Families and Tenants (LIFT) pilot that offers energy efficiency upgrades to low-income multifamily properties, and the MCEv program, an electric vehicle rebate program for low-income customers.

Additionally, MCE will pursue program leveraging with relevant programs run by partners and other local CBOs and government entities.

Figure 3. MCE ME&O Tactics and Strategies



*Component of CS-GT ME&O only. Due to auto enrollment provisions and to limit customer confusion about program eligibility, these tactics will not be used for the DAC-GT program.

5. METRICS TRACKING

Because MCE is using multiple tactics for ME&O, a variety of metrics will be used to evaluate the effectiveness of each effort. Our primary measure of effectiveness is the number of customers reached, which can be measured by:

- DAC-GT
  - Number of customers enrolled based on auto enrollment criteria;
  - Number of customers opting to cancel program participation.
- CS-GT
  - Total number of enrollees;
  - Total CARE and FERA enrollment achieved through CS-GT outreach;
  - Total number of customers reached;
  - Diversity in race, age and income of event participants, with participation that reflects census distribution demographics of the DAC communities;
  - Direct mail and email - email click-through and open rates;
  - Indirect website visits and page views, social media engagement and impressions;
  - Total number of events and distribution of events by neighborhood.

By regularly monitoring these measures, MCE will be able to make changes in its approach or shift the mix of ME&O channels to improve the effectiveness of outreach, if necessary. Additionally, feedback from CBO partners, surveys, on-the-ground interactions, and message testing could alter the strategy pursued.

FEBRUARY 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 (Filed May 7, 2020)

MARIN CLEAN ENERGY'S
FEBRUARY 1, 2021 INCREMENTAL PROCUREMENT COMPLIANCE FILING
[PUBLIC VERSION]

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February 1, 2021

**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 (Filed May 7, 2020)

**MARIN CLEAN ENERGY'S
FEBRUARY 1, 2021 INCREMENTAL PROCUREMENT COMPLIANCE FILING
[PUBLIC VERSION]**

Pursuant to Ordering Paragraph 1 of California Public Utilities Commission ("Commission") Decision ("D.") 20-12-044, issued in Rulemaking ("R.") 20-05-003 on December 22, 2020, Marin Clean Energy ("MCE") submits this compliance filing providing information about MCE's progress towards achieving the incremental capacity procurement requirements for years 2021, 2022, and 2023 set in D.19-11-016.

INTRODUCTION AND BACKGROUND

In D.19-11-016, the Commission ordered Load Serving Entities ("LSE") to collectively procure a total of 3,300 MW of incremental system capacity by 2023, with specific procurement obligations allocated to each LSE. MCE's assigned share of this requirement is 87.5 MW,[1] 50% of which must be online by August 1, 2021, 75% of which must be online by August 1, 2022, and 100% of which must be online by August 1, 2023.

As part of MCE's contribution to system reliability and renewable integration needs, MCE committed to self-providing its share of the identified system capacity need on February 18, 2020.[2] D.19-11-016 also directed LSEs to include an update on incremental procurement

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[1] D.19-11-016, Ordering Paragraph 3.
[2] *Marin Clean Energy's February 15, 2020 Integrated Procurement Planning Progress Report Pursuant to Decision 19-11-016 Adopted in Rulemaking 16-02-007*, filed February 18, 2020.

activities in their biennial IRPs, including contract and resource information and an attestation of compliance by a senior executive.[3] MCE provided the required update and attestation to meet this compliance requirement as part of its Integrated Resource Plan filed on September 1, 2020.

On December 22, 2020, the Commission issued D.20-12-044. This Decision adopted a compliance framework for D.19-11-016 procurement, including milestones each self-providing LSE must meet in order not to trigger backstop procurement on its behalf. The decision describes the 3 milestones, the showings that must be made to meet each milestone, and the evaluation criteria the Commission will use to determine compliance. D.20-12-044 also directed that for incremental resources that have achieved commercial operation and are capable of delivering energy, an LSE can achieve compliance and not trigger backstop procurement if the LSE demonstrates that such resources satisfy Milestone 3 by providing evidence that the resource is online and available.[4]

As part of this compliance filing, MCE includes a progress report, below, that describes its procurement activities pursuant to D.19-11-016 and D.20-12-044. Attached to this filing, MCE is providing a completed *Public Reporting Template for Backstop Procurement* provided by Energy Division on January 8, 2021, which includes publicly available information for each of MCE's incremental capacity resources (Attachment B). This compliance filing also provides the relevant supporting documentation required by D.20-12-044; documentation that demonstrates MCE has met Milestone 3 for its 2021 and 2022 compliance requirements. Additionally, MCE includes supporting documentation to demonstrate that MCE is working towards achieving Milestones 1, 2 and 3 to complete MCE's 2023 compliance requirement open position. MCE is providing public (redacted) versions of this documentation in its public filing,

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[3] D.19-11-016 at 85, Ordering Paragraph 13.
[4] D.20-12-044 at Ordering Paragraph 3.

and, concurrently with this submission, is filing a motion to file the confidential versions of this material under seal.

Given the aforementioned demonstration of compliance, MCE requests a finding of compliance for its 2021 and 2022 compliance requirements and requests the Commission *not* initiate backstop procurement on MCE's behalf for any of the three tranches of incremental procurement.

PROGRESS REPORT

MCE has executed agreements that MCE expects to fully satisfy its 2021, 2022 and 2023 incremental capacity requirements under D.19-11-016. To meet these requirements, MCE has 182.78 MW of nameplate incremental capacity under contract, which translates to 88.23 MW of September net qualifying capacity ("NQC").[5] This is capacity not included on the baseline resource list adopted in Rulemaking 16-02-007.[6] Of this 88.23 MW of September NQC, 73.41 MW of September NQC is already online and capable of delivering energy, and as such, meets Milestone 3 of D.20-12-044. This online capacity exceeds MCE's 2021 and 2022 procurement requirement under D.19-11-016, which is 65.63 MW for both years.

In the following sections, MCE provides narrative descriptions of specific incremental procurement efforts intended to meet its D.19-11-016 requirements to supplement the *Public Reporting Template for Backstop Procurement*. Additionally, MCE provides supporting documentation to demonstrate compliance with its 2021 and 2022 incremental procurement requirements (*i.e.* Milestone 3) and documentation to satisfy certain elements of D.20-12-044's Milestones 1 and 2 for MCE's 2023 incremental procurement open position.

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[5] D.19-11016, Conclusion of Law 19 (clarifying that requirements for capacity procurement are to be based on the NQC values of the resources for the month of September).
[6] *See Administrative Law Judge's Ruling Finalizing Baseline for Purposes of Procurement Required by Decision 19-11-016*, filed January 3, 2020, Rulemaking 16-02-007.

1. Procurement Tranches 1 & 2 - MCE's August 1, 2021 and August 1, 2022 Incremental Procurement Requirement (65.63 MW)

MCE's procurement requirement for August 1, 2021 and August 1, 2022 is 65.63 MW. To comply with these requirements, MCE must demonstrate it has achieved all 3 milestones described and adopted in D.20-12-044 *unless the relevant resources have already achieved their Commercial Operation Dates* ("COD"), in which case, D.20-12-044 allows LSEs to demonstrate compliance by providing only evidence establishing that the resource has met Milestone 3.[7]

MCE has procured 73.41 MW of eligible incremental September NQC from three resources that have already reached COD, are capable of delivering energy, and thus meet Milestone 3. As required by D.20-12-044, MCE is providing documentation establishing Milestone 3 status for each of these resources. MCE's full, unredacted documentation is being included in the confidential version of this filing, which is being filed under seal and confidentially provided to the Energy Division. A public version of this documentation with confidential information redacted is being provided in MCE's public version of this filing. MCE requests the Commission find MCE compliant with these requirements and not initiate backstop procurement on behalf of MCE for 2021 and 2022. These resources are described more fully below.

a. The Sutter Energy Center

On February 28, 2020, MCE executed a 3-year *Master Power Purchase and Sale Agreement Confirmation Letter* ("Agreement") with Calpine Energy Services, L.P. ("Calpine") for 69.55 MW of capacity from the Sutter Energy Center (CAISO Resource ID: SUTTER_2_CISO).

[7] D.20-12-044 at Ordering Paragraph 3.

The period for the Agreement began on January 1, 2021 and continues through December 31, 2023, which is consistent with D.19-11-016's requirement that commitments based on existing resources must "stay in place at least through the end of the resource adequacy summer months of 2023."[8] Additionally, D.19-11-016 defines the Sutter Energy Center as an incremental capacity resource.[9] Although physically located outside of the CAISO balancing authority, D.19-11-016 also indicates that the Sutter Energy Center is not an import for purposes of the capacity procurement ordered by the decision[10] and thus not subject to D.19-11-016's 20% limitation on import resources.[11]

The Sutter Energy Center is online, capable of delivering energy, and under contract with MCE. Because this resource is online MCE is required to address Milestone 3 by providing evidence of the project being online and capable of delivery energy. To demonstrate compliance with Milestone 3, MCE is providing public and confidential versions of the following documentation in its respective public and confidential filings:

- *Attachment C* – Executed *Master Power Purchase and Sale Agreement Confirmation Letter* with Calpine Energy Services, L.P.

- *Attachment D* – Screenshot of Sutter Energy Center listing on the CAISO's *Full Network Model Pricing Node Mapping (based on Full Network Model Release DB20M12)* ("Full Network Model"), updated December 7, 2020 (*see* the "GEN_RES" tab, row 2522).[12]

- *Attachment E* – Screenshot of Sutter Energy Center listing on the Commission's *2021 Net Qualifying Capacity List* (December 23, 2020 Version) ("Commission 2021 NQC List") (*see* the "Specific Imports" tab, Row 46).[13]

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[8] D.19-11-016 at 47.
[9] *Id.* at Ordering Paragraph 6.
[10] *Id.*
[11] The attached *Public Reporting Template for Backstop Procurement* reflects the Sutter Energy Center as a CAISO System resource.
[12] Available here: http://www.caiso.com/market/Pages/NetworkandResourceModeling/Default.aspx.
[13] Available here: https://www.cpuc.ca.gov/General.aspx?id=6311.

Attachment C demonstrates that MCE has this resource under contract. Attachments D and E demonstrate that the resource is online and capable of delivering energy.

b. *MCE Solar One*

The MCE Solar One project (CAISO Resource ID: RICHMN_1_CHVSR2 & RICHMN_1_SOLAR) is currently online and has been delivering energy since December 22, 2017 under a 15-year Power Purchase Agreement ("PPA"), with an option to extend to 20 years, between MCE and MCE Solar One, LLC. MCE Solar One is a 10.5 MW solar facility located in Richmond, California. MCE has the full 10.5 MW from this facility under contract for the full term of the PPA. According to CAISO's *Final Net Qualifying Capacity Report for Compliance Year 2021* ("CAISO 2021 NQC List"),[14] this resource has a combined September NQC of 1.47 MW. MCE Solar One's capacity is incremental capacity not reflected on the baseline resource list adopted in Rulemaking 16-02-007.[15] As such, MCE Solar One applies towards MCE's total incremental system capacity procurement compliance requirement.

To demonstrate compliance with Milestone 3, MCE is submitting public and confidential versions of this filing that include, respectively, public (redacted) and confidential (unredacted) versions of the following documentation:

- *Attachment F* – Executed *Power Purchase and Sale Agreement* between MCE and MCE Solar One, LLC
- *Attachment G* – Screenshot of Solar One listing on the CAISO 2021 NQC List (the "2021 NQC List" tab, rows 1300-1301)[16]
- *Attachment H* – Screenshot of Solar One listing on the Commission 2021 NQC List (*see* the "2021 NQC List" tab, rows 1293-1294).[17]

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[14] Available here: http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx.
[15] *See Administrative Law Judge's Ruling Finalizing Baseline for Purposes of Procurement Required by Decision 19-11-016*, filed January 3, 2020, Rulemaking 16-02-007.
[16] Available here: http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx.
[17] Available here: https://www.cpuc.ca.gov/General.aspx?id=6311.

Attachment F demonstrates that the resource is under contract with MCE. Attachments G and H demonstrate that the resource is online and capable of delivering energy.

c. *Waste Management Redwood Landfill*

The Waste Management Redwood Landfill project (CAISO Resource ID: NOVATO_6_LNDFL) is currently online and has been delivering energy since September 14, 2017 under a 20-year PPA between MCE and WM Renewable Energy LLC.

The project is a 3.9 MW landfill gas-fired generation facility located in Novato, California. According to the CAISO 2021 NQC List, this resource provides 2.39 MW of September NQC.[18] MCE has all generation from this project under contract. This capacity is not reflected on the baseline resource list adopted in Rulemaking 16-02-007.[19] As such, this project applies towards MCE's incremental system capacity procurement compliance requirement. To demonstrate compliance with Milestone 3, MCE is providing submitting public and confidential versions of this filing that include, respectively, public (redacted) and confidential (unredacted) versions of the following documentation:

- *Attachment I* – Executed *Power Purchase and Sale Agreement* between MCE and WM Renewable Energy LLC.
- *Attachment J* – Screenshot of WM Redwood Landfill listing from the CAISO 2021 NQC List ("2021 NQC List" tab, row 649)[20]
- *Attachment K* – Screenshot of WM Redwood Landfill listing from the Commission 2021 NQC List ("2021 NQC List" tab, row 647).[21]

[18] The Commission's IRP Resource Data Templates reflect that the Waste Management Redwood Landfill project has 3.51 MW of September NQC, but the CAISO 2021 Net Qualifying Capacity List and the Commission's 2021 NQC List show 2.39 MW for this resource. MCE is following the NQC accounting in the respective 2021 NQC lists, but notes this discrepancy for the Commission.

[19] *See Administrative Law Judge's Ruling Finalizing Baseline for Purposes of Procurement Required by Decision 19-11-016*, filed January 3, 2020, Rulemaking 16-02-007.

[20] Available here: http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx.

[21] Available here: https://www.cpuc.ca.gov/General.aspx?id=6311.

Attachment I demonstrates that the resource is under contract with MCE. Attachments J and K demonstrate that the resource is online and capable of delivering energy.

2. Procurement Tranche 3 - MCE's August 1, 2023 Incremental Procurement Requirement (87.5 MW)

Towards its 2023 requirement, MCE has a total of 73.41 MW of September NQC under contract and commercially operational from the resources described above. To meet the remainder of MCE's 2023 requirement, MCE is planning to rely on the Strauss Wind Project ("Strauss"), which is currently under construction. MCE has executed a 20-year PPA with Strauss Wind, LLC. The Strauss project has a nameplate capacity of 98.83 MW, and MCE estimates the September NQC to be 14.82 MW.[22] Strauss is a new grid resource that is not included on the baseline resource list adopted in Rulemaking 16-02-007,[23] and as such qualifies as an incremental resource.

Strauss is currently under construction and began construction in March 2020. Due to permitting and construction delays the project's original and revised CODs were missed. MCE communicated the most recent COD delay to Energy Division as part of MCE's December 2, 2020 response to Energy Division's November 24, 2020 *IRP Filing Resubmission Request*. MCE is currently in discussions with the developer of Strauss to determine a new COD for the project. Although an Interconnection Agreement has been executed and amended, MCE also understands that the developer is in the process of further amending the current executed and amended Interconnection Agreement to accommodate the yet to be determined revised COD.

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[22] The Commission's IRP Resource Data Templates reflect that Strauss has 14.85 MW of September NQC, MCE estimates the Resource Data Templates slightly overstate the September NQC, which MCE estimates to be 14.82 MW. For purposes of this compliance filing, MCE is using the lower NQC value, not the value in the Resource Data Templates.

[23] *See Administrative Law Judge's Ruling Finalizing Baseline for Purposes of Procurement Required by Decision 19-11-016*, filed January 3, 2020, Rulemaking 16-02-007.

MCE plans for this resource to satisfy MCE's incremental procurement open position for the tranche of procurement required to be online by August 1, 2023. Once a revised COD is determined, MCE intends to provide the Commission documentation to fully satisfy Milestone 1 in future compliance filings.

To demonstrate the Strauss project's progress towards compliance with Milestone 1, and its full compliance with Milestone 2, MCE is providing public and confidential versions of this filing that include, respectively, public (redacted) and confidential (unredacted) versions of the following documentation:

- *Attachment L* – Executed *Amended and Restated Renewable Power Purchase Agreement between Strauss Wind, LLC and Marin Clean Energy* and the *First Amendment to the Amended and Restated Renewable Power Purchase Agreement Between Strauss Wind, LLC and Marin Clean Energy*

- *Attachment M* – Recorded Memoranda of Wind Energy Leases and Agreements with Grant of Easement.

- *Attachment N* – Executed *Exhibit J to the Amended and Restated Renewable Power Purchase Agreement between Strauss Wind, LLC and Marin Clean Energy – Construction Start Date Certificate*

Attachments L and M demonstrate the project's progress towards meeting Milestone 1. Attachment L demonstrates that the resource is under contract with MCE. Attachment M demonstrates the project has secured the land rights needed for construction. Attachment N demonstrates that Strauss is currently under construction and as such fully meets Milestone 2. MCE will provide documentation of the remaining elements of Milestone 1 in future compliance filings once an updated COD is established and an updated interconnection agreement is executed.

VERIFICATION

As required by the January 8, 2021 Guidance Email, set forth in Attachment A is a signed verification affirming the facts set forth herein and in the *Public Reporting Template for Backstop Procurement*.

CONCLUSION

MCE thanks the Commission for its time in reviewing this compliance filing. As stated above, MCE requests that the Commission determine that MCE has fully met its 2021 and 2022 procurement requirements, and is on track to meet its 2023 procurement requirement. As such, MCE respectfully asks that the Commission not initiate backstop procurement on its behalf.

Respectfully submitted,

February 1, 2021

/s/ Nathaniel Malcolm

Nathaniel Malcolm
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Attachment A

Officer Verification

Consistent with the direction provided in Energy Division's January 8, 2021 Guidance Email, Marin Clean Energy provides this Officer Verification. I am an officer of the reporting organization herein and am authorized to make this verification on its behalf. The statements in this filing and the *Public Reporting Template for Backstop Procurement* are true of my own knowledge, except as to matters which are therein stated on information or belief, and as to those matters, I believe them to be true.

Executed on January 29, 2021, at San Rafael, California

Respectfully submitted,

DocuSigned by:
Dawn Weisz
A59878416EBC4E8...

Dawn Weisz
Chief Executive Officer
MARIN CLEAN ENERGY
dweisz@mcecleanenergy.org

Attachment B

LSE	Submittal Date	Resource	Note, if resource name is generic (provide descriptive name)	CAISO ID (if unit has been assigned one--otherwise enter N/A)	CPUC Contract ID	Seller Name	Nameplate MW of Unit	August NQC (MW)	September NQC (MW)	NQC Fraction	Local Capacity Status and Area	CPUC Contract Approval Date (if applicable)	CPUC Approval Reference (Decision #, Advice Letter #, if applicable)	Resource Technology Type (AUTO-FILL)	If storage, including hybrids: storage depth in MWh	If hybrid: generator technology type	If hybrid: is project adding storage to existing generator?	If hybrid: generator nameplate MW	If hybrid: storage nameplate MW	If hybrid: can hybrid charge from grid?
MCE	2/1/2021	SutterEnergyCC-Total		SUTTER_2_CISO	raonlyCALPINE_RA_34_NS_MCE	Calpine Energy Service, LP	275	69.55	69.55	0.25	CAISO System	N/A	N/A	thermal	N/A	N/A	N/A	N/A	N/A	N/A
MCE	2/1/2021	SutterEnergyCC-Total		SUTTER_2_CISO	raonlyCALPINE_RA_34_NS_MCE	Calpine Energy Service, LP	275	69.55	69.55	0.25	CAISO System	N/A	N/A	thermal	N/A	N/A	N/A	N/A	N/A	N/A
MCE	2/1/2021	SutterEnergyCC-Total		SUTTER_2_CISO	raonlyCALPINE_RA_34_NS_MCE	Calpine Energy Service, LP	275	69.55	69.55	0.25	CAISO System	N/A	N/A	thermal	N/A	N/A	N/A	N/A	N/A	N/A
MCE	2/1/2021	NOVATO_6_LNDFL		NOVATO_6_LDNFL	energyWM_MCE	WM Renewable Energy LLC	3.9	2.4	2.39	1	North Coast	N/A	N/A	biomass	N/A	N/A	N/A	N/A	N/A	N/A
MCE	2/1/2021	NOVATO_6_LNDFL		NOVATO_6_LDNFL	energyWM_MCE	WM Renewable Energy LLC	3.9	2.4	2.39	1	North Coast	N/A	N/A	biomass	N/A	N/A	N/A	N/A	N/A	N/A
MCE	2/1/2021	NOVATO_6_LNDFL		NOVATO_6_LDNFL	energyWM_MCE	WM Renewable Energy LLC	3.9	2.4	2.39	1	North Coast	N/A	N/A	biomass	N/A	N/A	N/A	N/A	N/A	N/A
MCE	2/1/2021	RICHMN_1_CHVSR2		RICHMN_1_CHVSR2	energyMCE Solar 1_8.5_MCE	MCE Solar One LLC	8.5	2.3	1.19	1	Greater Bay Area	N/A	N/A	solar	N/A	N/A	N/A	N/A	N/A	N/A
MCE	2/1/2021	RICHMN_1_CHVSR2		RICHMN_1_CHVSR2	energyMCE Solar 1_8.5_MCE	MCE Solar One LLC	8.5	2.3	1.19	1	Greater Bay Area	N/A	N/A	solar	N/A	N/A	N/A	N/A	N/A	N/A
MCE	2/1/2021	RICHMN_1_CHVSR2		RICHMN_1_CHVSR2	energyMCE Solar 1_8.5_MCE	MCE Solar One LLC	8.5	2.3	1.19	1	Greater Bay Area	N/A	N/A	solar	N/A	N/A	N/A	N/A	N/A	N/A
MCE	2/1/2021	RICHMN_1_SOLAR		RICHMN_1_SOLAR	energyMCE Solar 1_2.0_MCE	MCE Solar One LLC	2	0.54	0.28	1	Greater Bay Area	N/A	N/A	solar	N/A	N/A	N/A	N/A	N/A	N/A
MCE	2/1/2021	RICHMN_1_SOLAR		RICHMN_1_SOLAR	energyMCE Solar 1_2.0_MCE	MCE Solar One LLC	2	0.54	0.28	1	Greater Bay Area	N/A	N/A	solar	N/A	N/A	N/A	N/A	N/A	N/A
MCE	2/1/2021	RICHMN_1_SOLAR		RICHMN_1_SOLAR	energyMCE Solar 1_2.0_MCE	MCE Solar One LLC	2	0.54	0.28	1	Greater Bay Area	N/A	N/A	solar	N/A	N/A	N/A	N/A	N/A	N/A
MCE	2/1/2021	Northern_California_Ex_Wind		N/A	energyStrauss_MCE	Strauss Wind LLC	98.83	20.79	14.82	1	CAISO System	N/A	N/A	wind_low_cf	N/A	N/A	N/A	N/A	N/A	N/A
														#N/A						

Resource	Project Location: City	Project Location: County	Project Location: Zip Code	Commercial Operation Date in MM/DD/YYYY format (Projected if not yet online, actual if online)	Contract Start Date in MM/DD/YYYY format	Contract End Date in MM/DD/YYYY format	Tranche 1, 2 or 3 from D.19-11-016	Has there been a project delay since the last time you submitted this backstop procurement report?	Are you submitting a remediation plan with this report submittal?	Milestone 1: Is there a signed contract with the entity with contractual rights to the resource for provision of commercial technology?	Milestone 1: If yes there is a signed contract, what date was it signed? MM/DD/YYYY format.	Milestone 1: Is there an interconnection agreement with a demonstrated path toward deliverability by the online date required by D.19-11-016 in place?	Milestone 1: If yes there is an interconnection agreement, what date was it signed? MM/DD/YYYY format.	Milestone 1: Are there signed land leases or title deeds demonstrating project site control?	Milestone 1: If yes there are signed land leases or title deeds, what is the signing date that demonstrates full site control is gained? MM/DD/YYYY format.	Milestone 2: Is there a "notice to proceed" or similar contractual evidence of construction commencement for new construction projects that will result in new NQC as of D.19-11-016 and available by August 1 of each year (2021-2023)?	Milestone 2: If yes there is a notice to proceed, what is the date in the notice to proceed to start construction? MM/DD/YYYY format.	Milestone 2: Is there a signed contract for demand response, imports, or sales of excess resources between LSEs?	Milestone 2: If yes there is a signed contract, what date was it signed? MM/DD/YYYY format.	Milestone 3: Is there evidence that a project is online and capable of delivering energy, or in the case of demand response, load reduction? (I.e.., has project begun commercial operation or contributed to load reduction in the case of demand response?)	
SutterEnergyCC-Total	Yuba City	Sutter	95991	7/1/01	1/1/21	12/31/23	1	No	No	Yes	N/A - Already online		N/A - Already online		N/A - Already online		N/A - Already online	N/A	N/A - Already online	Yes	Tranches 1-3
SutterEnergyCC-Total	Yuba City	Sutter	95991	7/1/01	1/1/21	12/31/23	2	No	No	Yes	N/A - Already online		N/A - Already online		N/A - Already online		N/A - Already online	N/A	N/A - Already online	Yes	Tranches 1-3
SutterEnergyCC-Total	Yuba City	Sutter	95991	7/1/01	1/1/21	12/31/23	3	No	No	Yes	N/A - Already online		N/A - Already online		N/A - Already online		N/A - Already online	N/A	N/A - Already online	Yes	Tranches 1-3
NOVATO_6_LNDFL	Novato	Marin	94945	9/14/17	9/14/17	9/14/37	1	No	No	Yes	N/A - Already online		N/A - Already online		N/A - Already online		N/A - Already online	N/A	N/A - Already online	Yes	Tranches 1-3
NOVATO_6_LNDFL	Novato	Marin	94945	9/14/17	9/14/17	9/14/37	2	No	No	Yes	N/A - Already online		N/A - Already online		N/A - Already online		N/A - Already online	N/A	N/A - Already online	Yes	Tranches 1-3
NOVATO_6_LNDFL	Novato	Marin	94945	9/14/17	9/14/17	9/14/37	3	No	No	Yes	N/A - Already online		N/A - Already online		N/A - Already online		N/A - Already online	N/A	N/A - Already online	Yes	Tranches 1-3
RICHMN_1_CHVSR2	Richmond	Contra Costa	94801	12/22/17	12/22/17	12/22/37	1	No	No	Yes	N/A - Already online		N/A - Already online		N/A - Already online		N/A - Already online	N/A	N/A - Already online	Yes	Tranches 1-3
RICHMN_1_CHVSR2	Richmond	Contra Costa	94801	12/22/17	12/22/17	12/22/37	2	No	No	Yes	N/A - Already online		N/A - Already online		N/A - Already online		N/A - Already online	N/A	N/A - Already online	Yes	Tranches 1-3
RICHMN_1_CHVSR2	Richmond	Contra Costa	94801	12/22/17	12/22/17	12/22/37	3	No	No	Yes	N/A - Already online		N/A - Already online		N/A - Already online		N/A - Already online	N/A	N/A - Already online	Yes	Tranches 1-3
RICHMN_1_SOLAR	Richmond	Contra Costa	94801	12/22/17	12/22/17	12/22/37	1	No	No	Yes	N/A - Already online		N/A - Already online		N/A - Already online		N/A - Already online	N/A	N/A - Already online	Yes	Tranches 1-3
RICHMN_1_SOLAR	Richmond	Contra Costa	94801	12/22/17	12/22/17	12/22/37	2	No	No	Yes	N/A - Already online		N/A - Already online		N/A - Already online		N/A - Already online	N/A	N/A - Already online	Yes	Tranches 1-3
RICHMN_1_SOLAR	Richmond	Contra Costa	94801	12/22/17	12/22/17	12/22/37	3	No	No	Yes	N/A - Already online		N/A - Already online		N/A - Already online		N/A - Already online	N/A	N/A - Already online	Yes	Tranches 1-3
Northern_California_Ex_Wind	Lompoc	Santa Barbara	93436	TBD	TBD	TBD	3	Yes	No	Yes	10/19/2018 (Amended and Restated PPA); 02/21/2020 (First Amd. to Amended and Restated PPA)	No	*See* progress report: 07/27/2017 (Original); 04/10/2020 (Amended)	Yes	09/28/2015; 09/29/2015	Yes	3/20/20	N/A	N/A	No	Tranche 3

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026 (Filed June 29, 2017)

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON ASSIGNED COMMISSIONER'S AMENDED SCOPING MEMO AND RULING

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February 5, 2021

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026 (Filed June 29, 2017)

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON ASSIGNED COMMISSIONER'S AMENDED SCOPING MEMO AND RULING

Pursuant to the *Assigned Commissioner's Amended Scoping Memo and Ruling* filed December 16, 2020 (Amended Scoping Memo), the California Community Choice Association[1] (CalCCA) submits the following reply comments. The Amended Scoping Memo provided that: "[r]eply comments may be filed and served no later than February 5, 2021." In sum:

- No party opposes eliminating the Power Charge Indifference Adjustment ("PCIA") cap and trigger;
- Adopting the utilities suggestion for a Q1 implementation date will create more time for parties and the Commission to ensure rates are accurate, just and reasonable. Appendix A to these comments includes a model post-November Update schedule for the Commission's consideration;
- Improvements to the representation of the brown power benchmark component of the indifference calculation should be coupled with other changes to increase the accuracy of the forecast and reduce the volatility of the true-up;

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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, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, 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.

- Modifications to PG&E's, and *especially* SDG&E's, ERRA trigger framework to offset bundled customer balances should be made, provided more details are given; and

- The development of a renewable energy credit ("REC") tracking framework makes sense but will require substantial record development prior to adoption and implementation.

I. ELIMINATE THE PCIA CAP/TRIGGER

In a rare display of unanimity, all commenting parties agree that the PCIA cap/trigger should go. Commenters supporting elimination of the PCIA cap/trigger include the originator of the proposal (The Utility Reform Network), the mechanism's ostensible beneficiaries (unbundled customers), Southern California Edison Company (SCE), San Diego Gas and Electric Company (SDG&E), and Pacific Gas and Electric Company (PG&E) (collectively, IOUs), CalAdvocates, and the Coalition of Utility Employees (CUE). The parties' rationales for eliminating the PCIA cap/trigger vary, several of which CalCCA would dispute;[2] all commenters agree, however, that the PCIA cap/trigger has failed its fundamental purposes of reducing PCIA volatility and planning uncertainty.

Based on this widely shared conclusion, the Commission should eliminate the cap/trigger mechanism as soon as practicable. Operationally, the mechanism has been eliminated for 2021 in the SCE and PG&E service territories. The recent decisions in their Energy Resource and Recovery Account (ERRA) forecast proceedings effectively removed the cap for 2021, thereby preventing under-recovery in the PCIA Undercollection Balancing Accounts (PUBA) and the

[2] *E.g.*, CalCCA takes issue with CUE's collateral attack on D.18-10-019's creation of the PCIA cap/trigger.

need for a 2021 trigger.[3] Consequently, only a formal decision eliminating the mechanism is needed going forward.

An additional step is required in the SDG&E service territory. The SDG&E ERRA decision applied the cap for 2021, leaving the possibility of an undercollection accumulation in 2021.[4] As a result, eliminating the cap/trigger will take another year to fully implement. The Commission can still mitigate volatility in 2021, however, by directing that the 2021 undercollection be rolled forward to amortization in the next ERRA forecast proceeding. Indeed, this measure is consistent with the Stipulation submitted by CalCCA and SDG&E in the utility's recent expedited application to address the triggering of its PCIA Undercollection Balancing Account (CAPBA).[5]

II. MODIFY DEADLINES OR REQUIREMENTS OF ERRA AND PCIA RELATED SUBMITTALS TO INCREASE TIME FOR PARTIES TO REVIEW PCIA DATA AND TO FACILITATE TIMELY IMPLEMENTATION OF DECISIONS IN THE ERRA PROCEEDINGS

The IOUs state they "are open to exploring potentially moving the target ERRA implementation date, and the complete Consolidated January 1 rate change, back slightly (e.g., to a date within Q1)."[6] CalCCA agrees that pushing back the rate change date has merit. As the IOUs note, a Q1 rate change will maintain the ability for the November Update to use data from the critical late summer months and increase the accuracy of the true-up, bringing December actuals into the PABA balance via the implementation advice letters that will set PCIA rates.

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3 *See* D.20-12-038 at 18-19 (PG&E ERRA Decision); D.20-12-035 (SCE ERRA Decision) Finding of Fact 37 at 65.

4 *See* D.20-12-028 at 10.

5 A.20-07-009, *Joint Comments of San Diego Community Power, Clean Energy Alliance, Solana Energy Alliance, and the California Community Choice Association on the Proposed Decision*, Appendix B, *Joint Stipulation of SDG&E and CCA Parties*, ¶5.

6 R.17-06-026, *Joint Response of Southern California Edison Company (U 338-E), San Diego Gas & Electric Company (U 902 E) and Pacific Gas and Electric Company (U 39 E) to Assigned Commissioner's Amended Scoping Memo and Ruling*, at 15 (Jan. 22, 2021) (IOU comments).

Critically, moving the ERRA implementation date will also give the Commission *and parties* adequate time to review, analyze workpapers, conduct discovery on, and draft comments addressing the November update – a recurring shortcoming in the current schedule discussed in detail in CalCCA's opening comments.[7] Not surprisingly, the IOUs do not share this concern and propose giving all of the additional time – nearly two months – to the Commission's internal processes. They assert in opening comments that "one week to review the Update . . . .should be sufficient given that the Update is formulaic in nature and the information included should not raise any policy or substance issues." The IOUs then propose "to provide the Commission," but not parties, additional time to respond to the November update.

The IOUs' comments willfully ignore the experiences of the past several years to the contrary. In the past three years of ERRA proceedings, for example, the Commission has issued important decisions affecting PCIA calculations or bundled generation rates between the time of an Application and the November Update and required interpretation and implementation. PG&E's 2018 November Update presented for the first time the implementation of D.18-10-019, implementation of a brown power true-up that would be contested for months after the November update, the issue of vintage-specific billing determinants, use of a new common PCIA template implemented for the first time, the question of how to adjust balancing accounts for ERRA overcollections (an issue that is part of this revised scope of comments), and adjustments to tax savings caused by the Tax Cuts and Jobs Act.[8]

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[7] R.17-06-026, California Community Choice Association's Comments on Assigned Commissioner's Amended Scoping Memo and Ruling, at 17-19 (CalCCA comments).

[8] A.18-06-001, *Comments* on *Update* to *Pacific Gas* and *Electric Company's Prepared Testimony* o*f East Bay Community Energy, Marin Clean Energy, Monterey Bay Community Power, Peninsula Clean Energy, Pioneer Community Energy, Silicon Valley Clean Energy And Sonoma Clean Power*, at 11-30 (Nov. 19, 2019).

Similarly, the 2019 November Update presented for the first time implementation issues related to D.19-10-001, including issues surrounding the calculation of Retained RPS that PG&E has tried to litigate four times (and has suggested it be addressed a fifth time as part of the expanded scope in this case).[9] Finally, the 2020 November update presented for the first time the critical issue of which load forecast's billing determinants should be used to set SDG&E's bundled generation rates[10] and the inclusion of advice letters implementing CCA Green Tariff Shared Renewables programs, among others.[11]

Unless the Commission declares a moratorium on bundled generation rate or PCIA-related decisions between the months of June and November, the November update will continue to be anything but formulaic in nature. The real change the utilities should have identified is that few parties paid attention to the November Update prior to the past few years. However, the CCAs' close scrutiny of these proceedings, and the November update in particular, will not change any time soon.

Accordingly, additional time for parties to respond to the November update is necessary. Such additional time also would reduce the need for the shortened discovery timelines suggested in CalCCA's opening comments.[12] To advance that conversation, CalCCA proposes in Appendix A, a model post-November update schedule based on a March 1 effective date that could be adopted by the Commission as a general guide to be followed as closely as possible in future ERRA forecast proceedings.

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9 A.19-06-001, *Comments o*f the *Joint Community Choice Aggregators*, at 8-19 (Dec. 6, 2019).

10 A.20-04-014, *Joint Comments o*f *California Community Choice Association, San Diego Community Power* and *Clean Energy Alliance* to *San Diego Gas & Electric Company's (U 902 E) November Update To Application*, at 5 (Nov. 18, 2020).

11 A.20-07-002, *Opening Comments o*f the *Joint Community Choice Aggregators*, at 1-8 (Nov. 20, 2020).

12 CalCCA comments, at 22.

III. OTHER IOU PROPOSALS

The IOUs propose several "other procedural or information sharing related modifications the Commission should consider to support more efficient implementation of PCIA issues within ERRA proceedings."[13] The IOUs identify three specific proposals: "(1) improving the representation of the brown power benchmark component of the indifference calculation; (2) changes to PG&E's and SDG&E's ERRA trigger framework to consider offsetting bundled customer balances; and (3) a renewable energy credit ("REC") tracking framework."

A. Use of Generation Profile Rather than Load Profile for Forecasting Generation Value

The IOUs contend that "[u]se of historical bundled load data as a proxy to reflect the supply portfolio is increasingly inaccurate. . . .[T]he IOUs have experienced and will continue to experience increased load departures, meriting reconsideration of whether a dwindling bundled load portfolio is an acceptable proxy of the supply portfolio."[14] CalCCA agrees this issue merits further examination.

There is a related issue that should be considered in tandem in order to ensure that utility forecasts are as accurate as possible, reducing the degree to which true-ups cause swings in PCIA rates. It centers on how well the monthly Platts on peak/off-peak periods align with periods of high and low CAISO market prices. CalCCA observes that published market price forecasts such as Platts generally define the on-peak period as spanning the daytime period from hour ending 7 to 22. The potential mismatch between that definition of on- and off-peak periods and the hourly shape of prices in the CAISO market will mute the impact of changing the generation profile alone, as the IOUs suggest, because changing just the profile still leaves many hours

13 IOU comments, at 17.
14 IOU comments, at 17.

where generation during periods of low CAISO market prices would be multiplied by Platts on-peak prices, and vice-versa. This issue should be addressed to more closely align the PCIA forecast with the actual results that flow through the PABA for later true-up.

B. Offsetting Bundled Customer ERRA and PABA Balances

ERRA trigger filings have become an annual event. However, the balances that give rise to the ERRA trigger filings may be offset by balances in the PABA. This is because the same mechanisms that lead to one lead to the other. For example, a forecasting "miss" on energy prices that leads to an overcollection through the ERRA will lead to an undercollection in the PABA.

In practice, in PG&E's service territory, the offsetting nature of ERRA and PABA balances has led to ERRA trigger balances being applied to the following year's ERRA forecast.[15] While PG&E found ways to address this issue (and SCE avoided the issues altogether), SDG&E appears to have simply ignored the issue to date, creating the potential for numerous ERRA trigger filings in the same year.[16] CalCCA supports a streamlining of this process, and associated reduction in administrative burden, but more detail is needed on exactly how this streamlining would be done before the Commission can approve it.

In a related vein, CalCCA notes that its members currently lack sufficient information from the IOUs to gauge where ERRA and PABA balances are trending. The suggestion in the IOUs' comments that parties can "get an indication of the balance" is overstated at best.[17] The

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15 IOU Comments, at 18-19.

16 A.20-12-007, Exh. SDGE-3 at 4-5, Table 1 (showing that SDG&E's recent ERRA Trigger filing, from December 2020, is likely to be followed by another trigger in Spring. In the referenced table, subtracting out a $124M beginning balance, which would be recovered as part of the current ERRA trigger proceeding (A.20-12-007), leaves a $62M balance for March of 2021, which already exceeds SDG&E's 5% trigger threshold for 2021 of $37M).

17 IOU comments, at 14.

only balance information IOUs make public are monthly top-line balance levels that have already been booked. These summary level historical balances provide zero indication of the fundamentals causing the balances or the direction in which the balances might head in the future. The utilities also provide the balances on a lagged basis using data that are a month old by the time they are reported. CalCCA renews its request in its Opening Comments for more detailed balance information for its reviewing representatives and for consistent treatment of confidential information between IOUs.[18]

C. Renewable Energy Credit Tracking

The IOUs "support developing a framework to clarify requirements associated with the use of banked RECs to ensure bundled customers are not double charged if pre-2019 banked RECs are used for compliance, such as occurred in PG&E's 2020 ERRA Forecast."[19] The IOUs mischaracterize what happened in PG&E's 2020 ERRA Forecast; there was no "double charge" of bundled customers. In D.20-02-047, the Commission simply prevented PG&E from converting banked RECs into unsold RECs.[20] Following that decision, bundled customers retained, and still retain, the banked RECs at issue for their future use.

That said, a tracking mechanism for RECs is in everyone's interest to avoid future disputes about whether a REC belongs to bundled or unbundled customers. CalCCA recommends a workshop to explore these and the other issues discussed above.

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18 CalCCA comments, at 19-24.
19 IOU comments, at 19.
20 D.20-02-047 at 13-16.

IV. CONCLUSION

For all the foregoing reasons, CalCCA respectfully requests consideration of the proposals specified herein in addition to those raised in CalCCA's opening comments 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

February 5, 2021

Appendix A

CalCCA Proposed Post-November Update Procedural Schedule
Based on March 1 Rate Effective Date

Event	PG&E's 2021 Forecast (A.20-07-002)	PG&E 2020 Forecast (A.19-06-001)	New Implementation Date
November Update to Prepared Testimony Served	November 9, 2020	November 8, 2019	November 1 (as suggested in CalCCA's Opening Comments)
November Update Comments	November 20, 2020 (11 days)	December 6, 2019 (28 days)	December 1 (PG&E) (30 days) Thursday before Thanksgiving (SDG&E and SCE) (23 days, e.g.)
November Update Reply Comments			December 1 (SDG&E and SCE) (8 days)
Proposed Decision	December 4, 2020 (14 days)	January 24, 2020 (49 days)	First or second week of January (30-40 days)
Comments on Proposed Decision	December 11, 2020 (7 days)	February 13, 2020 (20 days)	Plus 20 days
Reply Comments on Proposed Decision	December 14, 2020 (3 days)	February 18, 2020 (5 days)	Plus 5 days
Final Commission Decision	December 17, 2020 (3 days)	February 27, 2020 (9 days)	Early February (1-2 weeks)
Effective Date of Implementation Advice Letter	January 1, 2020 (15 days)	May 1, 2020 (64 days)	March 1 (2-3 weeks)

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Consider New Approaches to Disconnections and Reconnections to Improve Energy Access and Contain Costs.	Rulemaking 18-07-005 (Filed July 12, 2018)

RESPONSE OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION TO THE ADMINSTRATIVE LAW JUDGE'S E-MAIL RULING REQUIRING RESPONSES TO THREE QUESTIONS CONCERNING ENERGY USE AND THE PERCENTAGE OF INCOME PAYMENT PLAN

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February 5, 2021

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Consider New Approaches to Disconnections and Reconnections to Improve Energy Access and Contain Costs.	Rulemaking 18-07-005 (Filed July 12, 2018)

RESPONSE OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION TO THE ADMINSTRATIVE LAW JUDGE'S E-MAIL RULING REQUIRING RESPONSES TO THREE QUESTIONS CONCERNING ENERGY USE AND THE PERCENTAGE OF INCOME PAYMENT PLAN

The California Community Choice Association[1] (CalCCA) respectfully submits these comments in response to the *Administrative Law Judge's E-Mail Ruling Requiring Responses to the Following Three Questions Concerning Energy Use and the Percentage of Income Payment Plan* (ALJ Ruling) issued December 7, 2020.

I. INTRODUCTION

CalCCA represents the interests of operating community choice aggregators (CCAs) and additional affiliated cities and counties interested in exploring the opportunities of community choice energy. CalCCA's members strongly support this proceeding's aim to reduce the number of customers experiencing disconnection after nonpayment. CalCCA supported the implementation of a Percentage of Income Payment Plan (PIPP) pilot in its January 8, 2021

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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, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, 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.

response to the first PIPP Ruling in the PIPP phase of this proceeding. Subsequently, the ALJ Ruling on energy use was issued, asking three questions that explore the application of an energy usage cap and the PIPP's potential impact on energy usage. CalCCA offers in these comments responses to the three questions posed in the ALJ Ruling. CalCCA recommends the following:

1 The Commission should implement the PIPP as a bill credit;

2 The Commission should require PIPP outreach materials to include information about the Energy Savings Assistance (ESA) program and Low Income Home Energy Assistance Program (LIHEAP) Weatherization program;

3 The pilot program should test the concept of an energy usage cap by applying a maximum PIPP bill credit to an experimental group of customers; and

4 The maximum PIPP bill credit should be developed by using the results of the Essential Usage Study and account for the different climate zones in California.

II. RESPONSES TO QUESTIONS

1. Will decoupling bills from energy use impact energy conservation and energy efficiency programs? Responses should be detailed and include as much information as possible.

CalCCA recommends that the Commission use the results of the PIPP pilot to determine if a customer's energy use increases once they are enrolled in the PIPP. At this stage in the proceeding, there is no evidence indicating that the PIPP would negatively affect energy conservation or hinder the achievement of California's energy efficiency goals.

However, to determine whether an energy usage cap for customers enrolled in the PIPP is needed, the PIPP pilot needs to test a control group (without an energy usage cap) and an experimental group (with an energy usage cap in the form of a maximum bill credit). CalCCA's response to Question #2 describes how this maximum bill credit could function. The results of such a pilot would allow stakeholders and the Commission to determine, through the examination of real data, whether decoupling bills from energy use impacts energy usage patterns.

2. Should there be an energy usage cap associated with any customer enrolled in the PIPP? Responses should be detailed and include as much information as possible.

For customers enrolled in the PIPP, the Commission should implement a PIPP bill credit for energy usage up to a certain dollar value, instead of a physical "energy usage cap" on the amount of electricity that a customer can use. Capping actual energy usage would be unlawful, counterproductive, and confusing for customers. Instead, the Commission should cap the maximum PIPP benefit (i.e., the bill credit that is applied to customers enrolled in the PIPP), similar to how the Arrearage Management Program caps the total arrears that can be forgiven at $8,000.

Under the PIPP, a customer pays a monthly bill that is a percentage of their yearly income divided by 12. The Utility Reform Network (TURN) and other parties have recommended that the percentages of income applied to customers on the PIPP be implemented as "a bill cap and not a replacement rate."[2] This would solve the problem that concerns the Public Advocates Office (PAO) and the National Consumer Law Center and the Center for Accessible Technology (NCLC & CforAT): the PIPP, if not implemented as a bill cap, could result in customers paying more for their energy than they would need to if they were paying their regular monthly bill (calculated based on the customer's usage and rate class).[3] The most straightforward way to put into effect the PIPP is to apply the financial benefit of being enrolled in the PIPP as a credit on

[2] TURN January 8, 2020 Opening Comments, at 3. See additionally, CCSF January 8, 2020 Opening Comments, at 3.

[3] PAO January 8, 2020 Opening Comments, at 2 and NCLC & CforAT January 8, 2020 Opening Comments, at 5.

customer's bills. The customer's monthly bill would be calculated the same way it was before they enrolled in the PIPP. If their monthly bill is under their bill cap amount (based on a percentage of their income), then they pay that bill. If it is over the bill cap amount, then the customer receives a bill credit that appears on their bill as their "PIPP benefit."

Furthermore, a maximum possible credit for this "PIPP benefit" should be adopted. For example, if a customer enrolled in the PIPP uses an amount of energy that results in their energy bill being four times the amount of their bill cap, they should not be credited the entire amount above their bill cap. Instead, the Commission should adopt a maximum PIPP benefit. The maximum PIPP benefit would be applied to the customer's bill and the customer would be responsible for paying for the costs of all usage in excess of their maximum PIPP benefit (see Table 1). This effectively caps the amount of energy usage to which the PIPP benefit could be applied.

Additionally, CalCCA recommends that the Commission move away from using the term "energy usage cap" and instead use the term "maximum PIPP benefit" to prevent confusion between the two caps being discussed in the proceeding: the "bill cap" and the "energy usage cap." The bill cap is calculated based on the customer's percentage of income. If a customer's bill ends up being larger than the bill cap, then the PIPP benefit (i.e., the bill credit) is applied. The maximum PIPP benefit functions as an "energy usage cap" on the amount of usage to which the PIPP benefit is applied but it is not an actual physical energy usage cap.

Table 1: Sample application of Maximum PIPP Benefit

Annual Household Income (4-person household)	$53,000
Applicable Bill Cap	4% of annual income ($2,120)
Monthly Bill Cap	$176.67
Maximum PIPP Benefit (illustrative)	15% more than Monthly Bill Cap = $203.16
Usage Scenario 1 (low)	**Usage Scenario 2 (high)**
Monthly bill total (usage * rate): $98	Monthly bill total (usage * rate): $245
Customer Pays $98	Customer Pays: $176.67 (Monthly Bill Cap) + $41.84 (billed amount above their Maximum PIPP Benefit: $245 - $203.16) = $218.51

Finally, CalCCA recommends that all customers that are enrolled in the PIPP be strongly encouraged to apply to participate in the ESA and the LIHEAP Weatherization service when they are enrolled in the PIPP because low-income customers are likely to make sacrifices by forgoing heating or cooling due to high energy costs. All PIPP marketing and outreach materials should clearly advertise the ESA and LIHEAP Weatherization programs and enrollment requirements. CalCCA also suggests that call service representatives and/or CBO partners should walk PIPP eligible customers through the application process, including providing technical assistance if needed. CBO partners that work directly with low-income customers could support designing scripts to describe the PIPP, ESA, and LIHEAP programs. By encouraging joint participation in existing energy efficiency services and the PIPP, the Commission can help advance the energy efficiency of low-income households and contribute to the comfort of low-income customers. CalCCA understands that this is one of many strategies for addressing affordability.

3. If there is an energy usage cap associated with the PIPP how should this be determined and what should the cap be? Responses should be detailed and include as much information as possible.

As was mentioned in response to Question 2, a physical energy usage cap should not be adopted. Instead, a maximum PIPP benefit should be developed and adopted. If a customer's energy usage results in a bill that is above their percentage of income bill cap, then a bill credit should be applied to their bill up to a yet-to-be determined maximum. To determine what the maximum PIPP bill credit should be, the Commission should use the results of the Essential Usage Study that is being carried out in A.19-11-019 to inform how much energy usage is essential. This quantity can then be used to calculate the maximum PIPP credit. D.20-09-021 approved the plan for the Essential Usage Study that is being conducted jointly by the investor-owned electric utilities and the draft report and web tool are expected to be completed by October 2021.[4] The web tool and draft report should be discussed as part of the PIPP Working Group and be used to develop the maximum PIPP bill credit.

If for any reason the Essential Usage Study is delayed and development of the PIPP must move forward, then CalCCA recommends that the Commission use the baseline electricity quantities that are currently in place until the Essential Usage Study results are made available. Because there are different baseline quantities in cool, hot, and warm climate areas across California, the maximum PIPP benefit should be set relative to

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4 D. 20-09-021, at 8.

the different baselines in each baseline territory. The maximum PIPP benefit should also allow for a certain amount of energy use above the current baselines (including medical baseline) to account for the fact that many low-income households have multiple residents living in a single household and may have inefficient appliances.

Furthermore, the Commission should adopt a process to revisit the maximum PIPP benefit. After each investor-owned utility files its annual consolidated revenue requirement and rate change advice letter (e.g., after PG&E's Annual Electric True-Up Advice Letter is filed), the Commission should review the maximum PIPP benefit amount and update it based on the upcoming rate increases. This is essential because rate increases will affect the amount of electricity or gas a customer can consume before reaching their maximum PIPP benefit. Similarly, customers should be able to move to a different bill cap bracket, if they experience a change in income.

III. CONCLUSION

CalCCA appreciates the Commission's consideration of this response and looks forward to continuing to work with the Commission and other stakeholders on the critical issues addressed herein.

Respectfully submitted,

Evelyn Kahl

Evelyn Kahl
General Counsel to the
California Community Choice Association

Dated: February 5, 2021

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

OPENING BRIEF OF THE
CALIFORNIA COMMUNITY CHOICE ASSOCIATION

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February 5, 2021

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SUMMARY OF RECOMMENDATIONS

CalCCA urges the Commission to:

- Develop a more careful needs assessment for Summer 2021 through stakeholder workshops, building from the CAISO stack analysis and the SCE loss of load expectation analysis.

- Pending further assessment of need, direct the IOUs to move forward with procurement based on the lower bounds of need – 1073 MW – identified in the CAISO stack analysis.

- Increase the PRM, temporarily, only as necessary to ensure sufficient CAISO backstop procurement authority for Summer 2021. The incremental procurement obligation between the PRM and the current collective RA requirements of jurisdictional LSEs requirement should be placed on the IOUs, without penalty. Pushing the obligation down through to individual LSE RA requirements would serve no purpose and would create uncertainty in the monthly RA market.

- Allocate any incremental procurement obligation equitably among the IOU based on proportional load shares.

- Require IOUs to provide LSEs access to more and improved customer data to enable more effective demand-side solutions and better load forecasting and scheduling.

**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

**OPENING BRIEF OF THE
CALIFORNIA COMMUNITY CHOICE ASSOCIATION**

Pursuant to Rule 13.11 of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission), and the schedule set forth in Assigned Commissioner's Scoping Memo and Ruling (Scoping Ruling) dated December 21, 2020, the California Community Choice Association[1] (CalCCA) submits this Opening Brief 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, dated November 20, 2020 (OIR) in the above-captioned proceeding.

I. INTRODUCTION AND SUMMARY

The Commission initiated the OIR to address two primary issues: how to increase energy supply and decrease demand during the peak demand and net demand peak hours in the event of

[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, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, 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.

an emergency heat storm in the summer of 2021.[2] The Commission's immediate focus is the supply-side of this question, including both generation or storage resource procurement and demand-side resources operating as "supply" such as demand response.[3]

In the Commission's urgency to address the potential reliability needs, however, certain of the OIR's guiding principles appear to be in danger. Significantly, the original intent of the OIR was to address remedial actions "on a measure by measure basis," "recognizing that some programs may benefit from further study."[4] In its list of questions to be addressed with respect to supply-side solutions the Commission explicitly recognized that further analysis is a necessary part of addressing the potential issue. In fact, the OIR specifically asks for comment to address this question:

> 10. Should the Commission undertake a stack analysis of the amount of resources that would be necessary for Summer of 2021?[5]

Under normal circumstances, a careful and considered analysis, such as a loss of load expectation (LOLE) analysis, should underpin any Commission-ordered procurement. Under current circumstances, however, the Commission has set aside the need for such analysis, ordering the investor-owned utilities (IOUs) to procure additional resources to prevent a reliability event in Summer 2021.[6]

CalCCA has not opposed taking measured actions to secure reliability but urges the Commission to moderate its response, considering all facts. Some parties have drawn attention

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[2] OIR at 12.

[3] See Proposed Decision of ALJ Stevens, R.20-11-003, Decision Directing Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company to Seek Contracts for Additional Power Capacity for Summer 2021 Reliability, January 8, 2021 (Proposed Decision).

[4] OIR at 11.

[5] Id. at 14.

[6] See generally Proposed Decision.

to the uncertainty surrounding the influence of the shortcomings in the CAISO's Residual Unit Commitment (RUC) process.[7] Without a more detailed understanding of the impact of the CAISO shortcomings, it is difficult to determine the incremental procurement need for Summer 2021. Even those parties that see a need do not agree on the total incremental procurement required. CalCCA shares their concern over uncertainty. Indeed, CalCCA's witness Nick Pappas highlighted inconsistencies and areas of disagreement in the available reliability analyses offered by the California Independent System Operator Corporation (CAISO) and Southern California Edison Company (SCE).[8] To ensure a "no regrets" outcome, however, CalCCA supports going forward with limited incremental procurement at the lower bound of the findings in the CAISO "stack" analysis, *provided* the Commission (1) shores up its analysis of through near-term stakeholder workshops and (2) reasonably bounds the IOUs' additional procurement.[9]

Further, the Commission should make every effort to ensure that the uncertainty raised in this proceeding does not interfere with normal resource adequacy (RA) market operations. This requires two steps. First, the Commission must provide guidelines to the IOUs through the pending decision in this proceeding to ensure that the resources they procure are truly incremental, and would not merely cannibalize the existing market other LSEs are relying on. Second, if the CAISO adopts a higher Planning Reserve Margin (PRM), as it proposes to fully

[7] Testimony of Samuel Golding on Behalf of the Utility Consumers' Action Network, January 11, 2021 (UCAN Direct Testimony (Golding)) at 5: 7-11; Prepared Opening Testimony of Bill Powers, P.E. on Behalf of the Protect Our Communities Foundation, January 11, 2021 (PCF Direct Testimony (Powers)) at 3: 6-9; Prepared Direct Testimony of Michel Peter Florio Addressing Selected Issues Regarding Electric System Reliability for 2021, The Utility Reform Network, January 11, 2021 (TURN Direct Testimony (Florio)) at 4:21- 5:25.

[8] Direct Testimony of Nicholas J. Pappas, Michael Hyams, Matthew Langer, Mahayla Slackerelli and Samantha Weaver on Behalf of California Community Choice Association, January 11, 2021 (CalCCA Direct Testimony); Reply Testimony of Nicholas J. Pappas on Behalf of California Community Choice Association, January 19, 2021 (CalCCA Rebuttal Testimony).

[9] CalCCA proposed reasonable parameters in its comments on the Proposed Decision. Comments of California Community Choice Association on the Proposed Decision, January 28. 2021, at 7-9.

enable its backstop authority,[10] the PRM should not be pushed down to LSEs through an increased 2021 RA requirement. Co-mingling this incremental procurement with LSE RA targets would significantly complicate and disrupt ongoing LSE activities to fill their Summer 2021 RA needs. Instead, the delta between the current and ultimate PRM should be uniquely placed on the IOUs, whom the Commission has placed in a role of responsibility. Recognizing the extreme challenge the IOUs face, they should not be penalized for failing to procure the added PRM increment; rather, the CAISO should be allowed to perform its backstop function.

Beyond these foundational issues, CalCCA supports the call of the Utility Consumers Action Network (UCAN) for improved access for all LSEs to Advanced Metering Infrastructure (AMI) data. While time is admittedly limited to implement improvements by August, improvements will help mitigate the possibility, as noted in the Root Cause Analysis, that LSEs may underschedule load during critical events.[11]

II. A THOROUGH NEEDS ASSESSMENT SHOULD BE DEVELOPED THROUGH WORKSHOPS

CalCCA lauds the hard and critical work of SCE and CAISO in their respective reliability analyses and recognizes the significance of their efforts to build an analytical record supporting decisionmaking for Summer 2021. Despite their expedited devotion of analytical resources, however, substantial differences exist between these analyses in both methodology and source data, and consequently, the two analyses reach different conclusions. In addition, while SCE's analysis reflects the preferred, industry-standard methodology – a stochastic loss of load

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[10] Opening Testimony of Dr. Karl Meeusen on Behalf of the California Independent System Operator Corporation, January 11, 2021 (CAISO Direct (Meeusen)) at 2: 21-23.

[11] Final Root Cause Analysis: Mid August 2020 Extreme Heat Wave, California Independent System Operator Corporation, California Energy Commission, California Public Utilities Commission, January 13, 2021 (Final RCA) at 61.

expectation (LOLE) – CalCCA is concerned with the inclusion of 584 MW of retired fossil units in SCE's baseline, which could significantly impact the quantitative outcome. Further analysis must be undertaken to reconcile the analyses inputs and differing conclusions. Consequently, the record falls short of answering the question of how much additional procurement is required for Summer 2021 or 2022. While CalCCA supports commencement of additional procurement to ensure a "no regrets" outcome for Summer 2021, a consensus on the need for procurement must be achieved before California ratepayers are asked to fund significant outlays for capacity.

A. Existing Needs Assessments Require Review and Reconsideration

CalCCA performed a detailed review of the SCE LOLE and CAISO stack analyses, both of which attempt to analyze whether expected generation in summer 2021 will meet system need, and outlines the results of its review below. As will be discussed, substantial caveats must be taken with both analyses.

CAISO's original analysis compares load to the net peak plus a 20% PRM, finding capacity shortfalls from July through September ranging from 452 MW (August) to 3,316 MW (September).[12] CAISO later submitted testimony calculating a proposed PRM of 17.5% for June – Oct 2021 to cover "both the gross system peak demand and to the most critical hour after peak, when solar production is very low or zero."[13] This proposed 17.5% PRM was calculated by taking into account a 6% contingency reserve requirement, a 4% difference between the CEC's 1-in-5 demand forecast and 1-in-2 demand forecast, and a forced outage rate of 7.2% based on analysis of data from the NERC Generator Availability Data System (GADS) dataset.[14]

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12 Comments of the California Independent System Operator Corporation on Order Instituting Rulemaking Emergency Reliability, November 30, 2020, Table 2, at 16.

13 Opening Testimony of Jeff Billinton on Behalf of the California Independent System Operator Corporation, January 11, 2021 (CAISO Direct Testimony (Billinton)) at 2: 14-15.

14 Id. at 3:9- 4: 16.

In its analysis, SCE ran the PLEXOS production cost model, and concluded that expected outages were at 0.09, meeting the 0.1 LOLE standard.[15] However, they acknowledge that "achieving that 1-in-10 LOLE reliability standard is heavily dependent on the on-time delivery of the 1,650 MW of system reliability procurement ordered by Decision (D.) 19-11-016 for August 2021 and what type of resources are procured."[16] In its review, CalCCA identified the inclusion of 8 retired fossil generators which were included in SCE's baseline, representing 584 megawatts of firm capacity not actually available in Summer 2021. It is possible that a revised analysis without these resources could fail the 0.1 LOLE standard and corroborate CAISO's conclusions regarding the need for additional Summer 2021 procurement.

SCE's methodology is preferable to the CAISO stack analysis, and a similar LOLE study should be revised and used as the basis for Summer 2021 procurement activities. As CalCCA explained in its direct testimony, stack analyses are less rigorous than other industry standard resource planning and reliability methods, and CAISO's analysis does not provide an assessment of the probability or level of risk associated with achieving, for example, slightly less or slightly more than the prescribed PRM. [17] In its direct testimony, TURN expresses similar concerns: "[s]uch a stack analysis [i.e. CAISO's] is a crude measure of reliability, however, and ignores the probabilities of various events occurring in favor of a single snapshot view."[18] Notwithstanding, TURN's witness finds that although "[o]ne could certainly quarrel with some of the assumptions in both the CAISO and SCE studies, . . . the robust SCE analysis should give this Commission

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15 Southern California Edison Company's (U 338-E) Comments on 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, November 30, 2020 at 16.

16 Id. at 2.

17 CalCCA Direct Testimony (Pappas) at 5: 14-16.

18 TURN Direct Testimony (Florio) at 9: 18-20.

considerable comfort that system reliability in 2021 will meet the adopted one-day-in-10-years standard, without any incremental generation procurement."[19]

However, SCE's analysis inadvertently included 584 MW of retired fossil resources which are no longer available to CAISO. But TURN's conclusion that the SCE analysis shows that the system will meet the established LOLE standard in 2021[20] — does not take into account SCE's inclusion of 584 MW of resources that had retired. If 584 MW had been removed from SCE's analysis, it is quite possible that the system's LOLE would have exceeded the 0.1 LOLE standard, and thus been unreliable.

While CalCCA agrees that an LOLE study is a more precise assessment of need, SCE's LOLE study, without a deeper dive, should not be considered the final answer on system reliability. In sum, there is no evidence in the record that gives the Commission a precise "answer" for the quantity of system need. The shortcomings in assumptions and the limited insights provided by CAISO's stack analysis leave neither SCE nor CAISO's analysis as a basis for procurement beyond a directional indication. California ratepayers deserve a more considered basis for additional capacity procurement.

B. Workshops Should Be Held to Revise the Needs Assessment Before Additional Procurement is Ordered.

The Commission should hold a workshop as soon as possible to resolve outstanding discrepancies between the CAISO and SCE input assumptions and methodologies, as detailed above. CalCCA has continuously stressed the need for workshops in this proceeding. CAISO explicitly agreed with CalCCA on the need for a workshop, stating that "a workshop will allow the CAISO and SCE to explain more fully their respective study assumptions and parameters. It

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[19] Id. at 10: 13-16.
[20] Ibid.

will also allow parties to ask questions about the analyses in a forum that allows for an open exchange of information.[21]

Stakeholder workshops are necessary to enable full and frank discussion of input assumptions and analyses so far conducted, and to seek buy-in for a methodological approach to the issue going forward. The workshops should have as their ultimate goals: (1) clearly defining how to quantify system need; (2) resolving discrepancies between the current analyses as necessary for agreement on a methodological approach; and (3) developing a clear path with unambiguous targets for addressing the assessed need.

California ratepayers deserve a complete and accurate assessment of the true need to be addressed. Ratepayers also deserve a considered approach to how best to address this need, including what methods are likely to be successful, before unlimited and unrestricted procurement adds chaos to an already pressed capacity market. Until that time, incremental procurement should be limited to 1073 MW, as discussed below in section IV, and the scope of procurement should be narrow to limit ratepayer exposure.[22]

C. The Commission Should Consider the Impact of the Shortcomings in CAISO RUC and Export Procedures in Bounding the Magnitude and Scope of IOU Incremental Procurement

Several parties lay responsibility for the blackouts, in part, on "a software error in the CAISO's RUC process."[23] Sam Golding on behalf of UCAN provides a detailed discussion of the RUC process:

> In terms of the design of the CAISO market, the RUC relies on CAISO's internal load forecast to ensure reliability, in part, because LSEs are not required to submit their full load forecasts as demand bid schedules. It is my understanding that CAISO does not assume

21 CAISO Rebuttal Testimony (Billinton) at 2: 18-21.

22 Comments of California Community Choice Association on the Proposed Decision, January 28, 2021 at 7-9.

23 UCAN Direct Testimony (Golding) at 6: 5-11; see also *supra* note 7.

> that the demand bids that all LSEs submit in the IFM in aggregate are representative of the next day's physical load, and that this is why the RUC process was designed to run (1) after the IFM clears and (2) using the CAISO's internal load forecast (which does forecast actual load on a day ahead basis and is thus the appropriate forecast to use to ensure physical supply). On Aug. 14 and 15, CAISO's internal load forecast should have been relied upon to schedule resources in the RUC sufficient to maintain system reliability. Because of the software glitch, however, the CAISO instead relied on the aggregate demand bids submitted by LSEs in the IFM.[24]

He further explains that because the "aggregate demand bids submitted by LSEs in the IFM was lower than CAISO's internal load forecast. Consequently, exports were scheduled in the Day Ahead Market at a level that exceeded what would have been necessary to maintain the supply-demand balance."[25] Mr. Florio on behalf of TURN reaches a similar conclusion and recommends that the Commission:

> Acknowledge that absent the Residual Unit Commitment software flaw that had yet to be discovered as of August 14-15, 2020, the rolling blackouts likely would not have occurred, and that with that software fix in place similar conditions over the Labor Day weekend did not result in firm load shedding.[26]

These parties raise an important point which arises from the failure of the Final Root Cause Analysis[27] to draw any conclusion regarding the magnitude of influence of any one of the three factors that purportedly caused the August 2020 events.

Incremental procurement to address 2021 will come at a cost to ratepayers. If UCAN and TURN are correct -- there would not have been load shedding "but for" the CAISO errors -- there is no reason to heap additional costs on ratepayers. Recognizing, however, that this factor has not been fully examined in this proceeding nor its impact quantified, CalCCA

[24] Id. at 7: 10-13.
[25] Id. at 7: 14-16.
[26] TURN Direct Testimony (Florio) at 1: 21-24.
[27] See generally Final RCA, Section 4 at 38-64.

supports consideration of this factor by carefully bounding the magnitude and scope of incremental procurement as discussed in Section IV of this brief.

III. IF NECESSARY FOR CAISO BACKSTOP PROCUREMENT, THE PRM SHOULD BE MODIFIED ON A TEMPORARY BASIS ONLY FOR SUMMER 2021 AND IMPOSE NO COMPLIANCE OBLIGATIONS ON INDIVIDUAL LSES

A. The Record Lacks Evidentiary Support for an Increased PRM

Modifying the PRM is one of several policy options to expand procurement for Summer 2021, but likely reflects one of the more disruptive and complicated policy approaches available to the Commission. CAISO recommended that the Commission adopt "a 17.5% planning reserve margin for June through October 2021," and that such a margin "should be maintained across both the peak load hours and the hours in the early evening when summer demands remain high and solar output is de minimus [sic]."[28]

As noted, until the full needs analysis CalCCA urges is undertaken, there is not sufficient evidence that such a step is required—or if so, what the increase should be. This is underscored by the fact, as noted by AReM/DACC, that no party beyond CAISO recommended increasing the PRM.[29] CAISO itself revised its opinion regarding the extent of the increase to recommend, originally proposing 20% and later 17.5%, as detailed above.

PG&E agrees, stating that "at this time, PG&E does not support a change to the PRM that is not supported by robust analysis and a stakeholder process. A 33 percent increase in the PRM (i.e., 15 percent to 20 percent) as proposed by CAISO in this proceeding is a very significant

[28] CAISO Direct Testimony (Billinton) at 1:18-22.

[29] Reply Testimony of Sue Mara on Behalf of the Alliance of Retail Energy Markets, Direct Access Customer Coalition, and the Regents of the University of California, January 19, 2021 at 6: 5-6.

change."[30] An abrupt change to a 17.5% PRM would presumably have a similar, and similarly unknowable, effect.

SCE also dismisses a PRM increase. SCE notes the precarious timing of an additional procurement requirement, particularly given market conditions:

> It is too late to impose increased RA requirements on LSEs for summer 2021. LSEs' RA showings for June 2021 are due on April 17, 2021 (approximately the same time as a final decision is expected in this rulemaking in March to April 2021) and July 2021 showings are due just one month later on May 17, 2021. This gives LSEs little to no time to procure to meet higher RA compliance requirements that the CAISO recognizes LSEs may not be able to meet due to limited resource availability.[31]

CAISO, however, submits that an increased PRM is necessary to enable its exercise of authority to procure under the Capacity Procurement Mechanism (CPM).[32] Assuming this to be an accurate assessment of the CAISO Tariff, there is merit in narrowly tailoring a PRM increase, with the limited scope of enabling more CPM procurement to safeguard against capacity shortfalls. Any modification must be temporary, however, and applied solely to 2021 summer months to enable CAISO to use the CPM to remedy identified shortfalls not resolved through IOU central procurement.

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[30] Pacific Gas & Electric Company Emergency Reliability OIR Prepared Testimony, January 11, 2021 (PG&E Direct Testimony (Clegg)) at 6: 10-13.

[31] Reply Testimony of Southern California Edison Company, January 19, 2021 (SCE Rebuttal Testimony (Walsh)) at 10: 12-13.

[32] "Increasing the planning reserve margin and providing for appropriate cost recovery measures will promote procuring the incremental resources needed to meet summer 2021 needs and will allow the CAISO to use its CPM authority most effectively." (CAISO Direct Testimony (Meeusen) at 5; 1-3; "If the Commission directs increased capacity procurement for 2021—without an attendant increase in the planning reserve margin—the CAISO will not have authority to issue a monthly deficiency CPM if the incremental capacity is not procured." CAISO Rebuttal Testimony (Meeusen) at 1: 22-25.

B. Incremental Procurement Requirements Should Rest with the IOUs and Not Be Added to the 2021 RA Requirements for Any LSE

If the 2021 PRM is increased, any incremental procurement obligation should remain an IOU-level requirement that is not added to LSEs' 2021 RA requirements. "Pushing down" the procurement need into individual RA requirements will unnecessarily disrupt in-progress contract negotiations, disrupt the market, and raise the costs of RA. Doing so would be unnecessary and counterproductive to the Commission's goals in this proceeding.

The Commission has already signaled in the Proposed Decision its intent to centralize procurement of this incremental capacity in the IOUs. The Commission presumably decided that requiring individual LSEs to procure would add confusion by adding buyers working against each other in an already tight capacity market. It no doubt could not be done as quickly if the responsibility were spread among [44] LSEs. Instead, it is entirely logical that the IOUs be assigned to procure for their TAC areas given the emergent nature of the need.

If the Commission's goal in centralizing the procurement was to decrease confusion and expedite procurement, allowing the RA requirement to be pushed down would serve little purpose. There is no obvious benefit to allowing the actual RA obligation to be pushed down to LSEs. Requirements aim to encourage certain actions by LSEs; here, no action is required. Flowing the requirement through to individual LSEs would simply complicate RA procurement for the remainder of the year.

If the purpose of increasing RA requirements is strictly to enable CAISO backstop at certain levels for Summer 2021, flowing the requirements through to individual LSEs is also unnecessary. The Commission should leave the incremental RA requirement, as with the procurement obligation, with the IOUs. In addition, it should make clear that no penalties will attach to this requirement because of the unique circumstances and the uncertainty about whether, in fact, the required incremental procurement is possible by August 2021.

IV. AUTHORIZED SUPPLY AND DEMAND SOLUTIONS MUST BE LIMITED UNTIL FURTHER ANALYSIS IS COMPLETED

CalCCA appreciates that potential reliability events in Summer 2021 would have a high societal cost. Understandably, it seems more reasonable to err on the side of being "long" rather than "short." However, to avoid errors of magnitude, until further analysis establishes a clear and unambiguous need, CalCCA urges the Commission to place firm limits on any procurement ordered.

A. Incremental Procurement Should Not Exceed 1,073 MW Without Further Analysis

CAISO's analysis shows a shortfall of 1,073 MW (relative to the current 15% PRM requirement) at HE 20 (the net peak) in September 2021.[33] Notwithstanding the methodological concerns with using a stack analyses as a basis for procurement, as described above, CalCCA believes that this is a reasonable first upper bound approximation of the system need, for several reasons.

First, a resource stack that falls short of even the current 15% PRM standard by 1,073 MW is concerning. Regardless of the shortcoming of stack analyses, such a shortfall provides strong directional evidence that there is a potential need of a significant magnitude.

Second, given the high social costs of outages, it is much more reasonable to err on the side of being "long." In other words, even though the CAISO system may not experience load curtailment without remedial action, there is sufficient risk of a reliability event to merit immediate remedial action.

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33 Comments of the California Independent System Operator Corporation on Order Instituting Rulemaking Emergency Reliability, November 30, 2020, Table 2, at 16.

Third, while stack analyses are imprecise, the CAISO analysis was based on reasonable assumptions – the use of the current NQC list, the assumption of average import showings, the analyses of specific hours of concern, and the use of a planning reserve margin reasonably informed by current understandings of generator outages and demand risk. Therefore, the quantity of need determined by the stack analysis, while imprecise, is likely accurate in its general magnitude.

Thus, as a "least-regrets" starting point, CalCCA recommends authorizing supply and demand solutions only up to a cumulative total of 1,073 MW, the need identified by CAISO, without further analysis. CalCCA recommends that this as an upper bound to immediate procurement, recognizing there is still limited risk of significant over-procurement should greater precision indicate a reduced need.

B. Procurement Should Be Limited to Short-Term Contracting for Summer 2021 Only

Procurement should be focused on Summer 2021 and exclude consideration of future procurement periods unless and until further analysis is conducted. CalCCA has stated that "[t]he Commission can best acknowledge [other stakeholders'] concerns by reasonably limiting the scope of new procurement and avoiding any new, significant, long-term commitments" (emphasis added).[34] As CalCCA has previously stated, contracts should have a maximum duration of three years, but preferably one.[35] TURN also stresses the importance of restricting procurement to "a short-term emergency basis," although TURN recommends such contracts not

34 CalCCA Rebuttal Testimony (Pappas) at 4: 10-12.

35 "The Commission should articulate a preference for one-year transactions, or three years or less should one-year transactions prove infeasible." 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, December 18, 2020 at 5.

exceed three years.[36] CEERT agrees, stating that "any procurement authorized in this proceeding, particularly gas-fired generation, must be limited to short-term contracts."[37]

Significant additional capacity is already scheduled to come online in 2021, 2022, and 2023 in response to the Commission's procurement order in D.19-11-016. It is unwise to commit now to other long-term contracts on top of this already existing mandate because it could result in costly redundancy. With respect to procurement for Summer 2022, there is ample time to review and consider the highlighted sensitivities in the CAISO and SCE needs assessments and to prepare a more precise and detailed needs assessment for that period.

Furthermore, because additional resources will be coming online after September 2021, the need during the Summer 2021 is likely to be transitory. Thus, any imminent procurement must tailored to the specific, imminent, period of need, to avoid unnecessary disruption in the RA markets, and unnecessary costs.

Finally, ratepayer impacts seem to be a missing puzzle piece in the Summer 2021 discussions. No analysis of the cost impacts of multi-year contract commitments has been developed in the record, and thus the additional cost burden of adding multi-year contracts is unknown. The Commission should not "lock in" expensive long-term contracts to address a short-term need, especially when reliability needs and load migration in 2023 and beyond are unclear.

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36 Prepared Reply Testimony of Michel Peter Florio Addressing Selected Issues Regarding Electric System Reliability for 2021, The Utility Reform Network, January 19, 2021 at 16: 20-17: 1.

37 Rebuttal Testimony of the Center for Energy Efficiency and Renewable Technologies (Caldwell, Jr.), January 19, 2021 at 2: 8-9.

C. Demand-Side Solutions Will Be More Feasible Solutions to Implement by August

CalCCA has consistently urged that "[b]oth supply and demand-side procurement should be considered" to meet system needs."[38] However, CalCCA believes that given the short time frame, demand-side solutions are likely more feasible. In fact, significant supply-side solutions may not be possible.[39]

Other stakeholders agree. For example, Pacific Gas and Electric Company (PG&E) flags issues with increasing supply side resources' output in the short term, including challenges with air permits, lead times for materials and services, and changes to interconnection agreements.[40] SCE concurs with this view, stating: "Of the two options of reducing energy demand or increasing energy supply, the options that reduce demand are more likely to be achievable in meaningful quantity by the summer of 2021."[41] SCE then provides a list of demand-side proposals, including an ELRP pilot and expansion of various DR programs. [42]

V. THE QUANTITY PROCURED SHOULD BE ALLOCATED EQUITABLY AMONG IOU TAC AREAS

As discussed above, there is no consensus on a particular "target" amount of capacity that should be procured, or in fact, whether there is a need at all. The testimony of TURN's witness is instructive, identifying the extreme rarity of the events that occurred in August, 2020, and the high cost and limited practicality of supply-side procurement.[43]

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38 CalCCA Rebuttal Testimony (Pappas) at 7: 21-22.

39 Id. at 8: 1-3.

40 PG&E Opening Testimony (Clegg) at 5-2: 10-14.

41 Direct Testimony of Southern California Edison Company (SCE Direct Testimony (Keating)) at 2: 10-11.

42 Id at 2:9- 3: 1 at 2:9- 3:17.

43 TURN Direct Testimony (Florio) at 6: 11-13 and 6:21-7:3.

As a result, the Commission has also not yet established limits on what each IOU should individually procure. In order to avoid excessive, costly, and potentially duplicative procurement, CalCCA urges the Commission to limit each IOU's procurement to no more than its proportional load share for its bundled customers and unbundled customers in its service territory. Other stakeholders echo this recommendation. For example, PG&E advocates "each IOU to procure on behalf of customers within their service territories."[44] SCE recommends part of the shortfall be satisfied through procurement of firm imports, again by the IOUs on behalf of the customers in their service territories.[45]

VI. THE IOUS SHOULD CONTINUE TO IMPROVE LSE ACCESS TO METER DATA.

The Final Root Cause Analysis concludes that underscheduling of load during the heat storm events contributed to the insufficiency of resources during critical periods.[46] UCAN raises concerns regarding the quality of meter data available to CCAs to be used in forecasting and scheduling load in the Day Ahead Market.[47] UCAN observes "delays in accessing smart meter data, and other operational barriers due to the IOUs' control over metering and billing functions, additionally degrade the ability of non-IOU LSEs to offer dynamic rate options and other retail product innovations."[48]

CalCCA shares UCAN's concerns and urges more strident efforts by the IOUs to ensure that the best data possible is available to all LSEs – including the IOUs themselves – to enable more accurate scheduling. In particular, the ability to quickly revise forecasting models with

44 PG&E Direct Opening Testimony (Clegg) at 6-3: 6-8.
45 SCE Direct Testimony (Walsh) at 49: 23-25.
46 Final RCA at 5.
47 UCAN Direct Testimony at (Golding) at 9: 1-5.
48 Reply Testimony of Samuel Golding on Behalf of the Utility Consumers' Action Network, January 19, 2021 at 4: 8-11.

new information from events such as heat storms or changes in load patterns due to stay-at-home orders is significantly hampered by delays in LSE access to data.[49] In addition, better data will also enable CCAs to implement key programs such as critical peak pricing programs.[50]

CalCCA supports UCAN's recommendation to "require all three IOUs to offer a Service Level Agreement (SLA) to provide non-IOU LSEs with the smart meter interval data collected by the IOUs' mesh networks each day, such that the data is received by non-IOU LSEs several hours prior to the CAISO's Integrated Forward Market demand-bid submission window.[51] CalCCA understands the complexity of this task given current IOU billing system constraints, but the priority of this issue should be elevated to create solutions, both near- and long-term.

VII. CONCLUSION

For the foregoing reasons, the Commission should adopt the recommendations presented in this opening brief.

Respectfully submitted,

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California Community Choice Association

February 5, 2021

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49 UCAN Direct Testimony (Golding) at 9: 1-7.
50 See CalCCA Direct Testimony (Hyams) at 26.
51 UCAN Direct Testimony (Golding) at 20:10-13.