BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Establish a Framework and Processes for Assessing the Affordability of Utility Service.	Rulemaking 18-07-006 (Filed July 12, 2018)

OPENING COMMENTS OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION IN RESPONSE TO THE ADMINISTRATIVE LAW JUDGE'S RULING INVITING COMMENTS ON STAFF PROPOSAL

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I. Introduction

Pursuant to the *Administrative Law Judge's Ruling Inviting Comments on Staff Proposal,* issued August 20, 2019 ("ALJ Ruling"), the California Community Choice Association ("CalCCA") submits these opening comments on the "Staff Proposal on Essential Service and Affordability Metrics," ("Staff Proposal") developed by Commission Staff from the Water, Energy, and Communications divisions. The ALJ Ruling invites parties to comment on the Staff Proposal, and includes four questions which parties may also address.

CalCCA appreciates the tremendous work of staff on the development of the Staff Proposal. Overall, the proposed metrics are very well-researched, thoughtful, and will support the overarching goal in this proceeding to assess the impacts of utility rate requests on affordability for customers. In these opening comments, CalCCA offers several specific suggestions and responses to questions in the ALJ Ruling.

In summary, CalCCA recommends that the Commission:

- Adopt the affordability reporting template proposed by the Public Advocates Office at the April 24, 2019 meeting of the Commissioner Committee on Emerging Trends, [1] and adapt it to reflect the metrics included in the Staff Proposal.
- Define, for each proposed metric, what constitutes "substantial hardship," to better align with the definition of "affordability" included in the Staff Proposal.
- Apply affordability metrics in two ways: (1) in the design of programs to assist customers facing hardship, based on an assessment of the cumulative affordability impacts of utility bills across all three utility sectors, and (2) in the decision-making process to approve new rate requests, based on an assessment of the incremental impacts of cost-causing filings within the utility sector in question.

[1] "Rate Trends 2009-2019." Presentation by Elizabeth Echols, Matthew Karle, Nathan Chou. April 24, 2019. Available at https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2019/Cal%20Advocates%20Rate%20Trend%20Presentation%20-%20April%2024th%202019.pdf.

- Adopt two additional metrics as indicators of the inability of households to pay for essential services: number of disconnections, and number of households in arrears for more than 60 days.
- Implement refinements to the proposed metrics, specifically:
    1. Calculating an Affordability Ratio for 1-person households, since they have the lowest median household income.
    2. Using CalEnviroScreen's Housing Burden Percentile score as a proxy for the Ability to Pay Index ("API"), if in the future the API dataset is no longer available or current.

These recommendations are described in more detail below.

II. Responses to Questions in ALJ Ruling

1. Do the proposed affordability metrics adequately assess affordability? If not, how should the metrics be changed?

Overall, yes. The proposed metrics include (1) Affordability Ratio ("AR"), which tracks how much of household income, after housing costs, goes to utilities; (2) Hours at Minimum Wage ("HM"), which reflects the number of hours an individual must work in order to pay for basic utility service; and (3) Ability to Pay Index ("API"), which includes an overall measure of economic vulnerability. Overall, the metrics are well-suited for assessing affordability because – particularly in the case of AR and API, which take income and housing expenses into account – they reflect both regional costs and ability to pay. CalCCA also strongly supports Staff's proposed method for calculating AR, since it incorporates individual household income and housing cost data while relying on publicly available information.

While the metrics are adequate overall, CalCCA recommends two specific refinements. First, CalCCA proposes that the AR be used to evaluate 1-person and 4-person households instead of 2-person and 4-person households. The Staff Proposal presents an example approach for presenting the AR in which 2-person and 4-person household AR values were computed and states that the AR could be calculated for other household sizes as well.[2] CalCCA supports doing so and notes that if there are ever constraints on how many different variations of AR can be calculated, then the calculation of 1-person and 4-person households should be prioritized. This is because 1) 1-person households have the lowest median household income,[3] and calculating the AR for 1-person households might make the AR seem smaller if it is a 2-person household with two incomes, since that would increase the size of the denominator in the ratio; and 2) there is more heterogeneity in 2-person households (e.g., could be a household with a single parent and child, a household with more than one income source, or a retired couple with a fixed income).

Second, the proposed metrics could be further improved by including the costs of essential expenses like childcare, medical expenses, and transportation in the AR and API calculations. The Staff Proposal's rationale for excluding these costs is largely based on practical considerations, such as data mismatches and the fact that housing costs represent the largest portion of most household budgets.[4] CalCCA maintains that transportation and child care costs can be significant for some households, particularly in California, and should be further considered for inclusion in metric calculations.

Finally, in considering whether the proposed metrics adequately assess affordability, we note that the proposal defines affordability as, "the degree to which a household can regularly pay for essential service of each public utility type on a full and timely basis without substantial hardship"[5] (emphasis added). While the proposed metrics are a very strong step in the right direction, CalCCA believes they can be advanced to better align with the definition of affordability included in the Staff Proposal in two ways. First, to better capture whether households can "regularly pay" for essential service, the Commission should track as an additional metric in this proceeding the number of utility disconnections. We also suggest

[2] Staff Proposal, p.29.
[3] "Median Household Income in the Past 12 Months (in 2017 Inflation-Adjusted Dollars) by Household Size." 2017 American Community Survey 1-Year Estimates for California. Table B19019. https://factfinder.census.gov/faces/tableservices/jsf/pages/productview.xhtml?pid=ACS_17_1YR_B19019&prodType=table.
[4] Staff Proposal at p.18,
[5] Staff Proposal at p.6.

tracking information on the number of households in arrears for more than 60 days in a year, since such data would indicate "hardship" in making payments despite not being disconnected.

Second, to better capture which households experience substantial hardship, it is necessary to define, for each proposed metric, what constitutes hardship. For example, approximately how many additional hours worked to afford a utility bill increase would result in substantial hardship for a given customer segment? As stated in the OIR, one goal of this proceeding is to "Develop a framework and principles to…define affordability criteria."[6] Without clear guidelines in place for consideration of "substantial hardship," the Commission risks spending considerable staff time developing complex metrics that are ultimately not actionable because they do not lend themselves to defining affordability. CalCCA recommends that subsequent versions of the Staff Proposal also include a section on interpretation and implementation of these metrics. To assist the Commission in this effort, CalCCA provides several suggestions for interpretation and use of the metrics below, in response to Question 4.

2. Are the proposed sources of data for household-level information acceptable for constructing affordability metrics? If not, what sources would be more appropriate, and why?

Yes. The proposed sources of data are desirable because they are publicly accessible (e.g., through the American Community Survey datasets, county websites, and/or online through NREL) and developed based upon well-established methodologies.

The Staff Proposal notes, however, that the existing API dataset may not be updated in the future. If and when the API data are no longer available, the Commission could look to the "Housing Burden" score in CalEnviroScreen's Excel-based dataset as an alternative source of similar information. This dataset is developed based on a well-established methodology, is publicly available, and the Excel-based format is easily accessible.[7]

[6] OIR at p.2.

[7] CalCCA does *not* recommend using the CalEnviroScreen Cumulative Score for this purpose because the score includes variables that are not relevant to affordability.

The CalEnviroScreen Housing Burden Percentile data is similar to API because both datasets account for the cost of housing and household income by census tract. Specifically, Housing Burden Percentiles in CalEnviroScreen indicate the relative extent to which households in a given census tract are both low income (defined as those making less than 80% of their county's median family income) and severely burdened by housing costs (defined as those paying greater than 50% of their income for housing costs).[8] Similarly, API groups customers by income level (as a percentage of AMI) and percentage of income spent on housing, producing a weighted score for households in each census tract. If, in the future, API is no longer available, customers could thus be grouped by the CalEnviroScreen Housing Burden Percentile instead of the current practice.

3. **What regulatory, operational, and/or resource considerations might be necessary to effectively implement affordability metrics? How should the Commission monitor and track affordability on a recurring basis, outside of specific proceedings?**

To track affordability on a recurring basis, outside of specific proceedings, CalCCA strongly supports adopting the Public Advocates Office proposed reporting template,[9] and adapting it to reflect the affordability metrics included in the Staff Proposal. The template is designed to comprehensively track the cumulative rate and bill impacts across cost-causing filings. As currently designed, the reporting template includes line items for individual proceedings or applications. It would capture the revenue requirements, bill impacts, and rate impacts of cost causing filings, and would also track the rate recovery mechanism. The Public Advocates Office has noted, and CalCCA agrees, that a key benefit of the reporting template is that it would better allow the Commission to consider cumulative impacts, which is more

[8] See https://oehha.ca.gov/media/downloads/calenviroscreen/report/ces3report.pdf#page=135, page 127-130.

[9] See slides 29-32, Public Advocates Office presentation on "Rate Trends 2009-2019," presented April 24, 2019 at Commissioner Committee on Emerging Trends. Available at https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2019/Cal%20Advocates%20Rate%20Trend%20Presentation%20-%20April%2024th%202019.pdf

meaningful than assessing the impact of a single request in isolation.[10] Inclusion of the staff-proposed affordability metrics in the affordability reporting template would retain this benefit.

Additionally, CalCCA recognizes that the data collection and analysis efforts associated with development of these metrics may be time consuming. However, CalCCA believes that once the general analytical framework is in place, the use of macros and other software tools could help partly automate the data collection and analysis process. CalCCA members are happy to work with Commission staff to develop this technical framework.

Finally, to ensure that the Commission is identifying all significant household types, CalCCA recommends it consider how to account for the percentage of unconventional households, such as roommates comprised of people who are not in a familial or domestic partnership arrangements, but who share a dwelling as a matter of economic necessity. The percentage of individuals in these sorts of living arrangements comprises a significant percentage of "households," likely given high housing costs in portions of the state. Indeed, according to the American Community Survey, approximately 17% of households in California are "nonfamily households."[11]

4. When and how should affordability metrics be utilized in Commission decisions and program implementation?

a. How should the Commission use or interpret the resulting values from affordability metrics in proceedings?

Affordability metrics should have two related but distinct areas of application. First, *cumulative* impacts, based on utility bills today, should be considered in the development of programs targeted to assist customers facing hardship. (Please see CalCCA response to question 4b, below, for additional suggestions on how these metrics can be used to develop targeted customer programs.) Secondly, *incremental* impacts of pending rate requests, through rate cases

[10] Public Advocates Office Reply Comments at p. 11

[11] "Household Type by Relatives and Nonrelatives for Population in Households." American Community Survey. 2017 1-Year Estimates for California. Table B11002. https://factfinder.census.gov/faces/tableservices/jsf/pages/productview.xhtml?pid=ACS_17_5YR_B11002&prodType=table

or applications, for example, should be tracked for the purpose of informing Commission decisions to approve new rate increases.

To ensure Commissioners have the best-available information when approving rate increases, CalCCA also recommends separately calculating affordability metrics associated with the type of utility in question, as staff did in the workshop presentations on August 26. In other words, if Commissioners are approving an electric rate increase, affordability metrics should be calculated based on essential service of electricity only. The Staff Proposal recommends assessing affordability *across* the three types of utilities; however, affordability assessments of a proposed bill increase based on a single utility are more intuitive to understand. Moreover, the Commission must balance interests to prevent one utility sector from constraining another from necessary cost decisions within its sector in the name of overall affordability. In such an instance where the cumulative burden is deemed to cause hardship, the Commission is encouraged to find ways to relieve the cost burden without harmfully constraining a utility sector.

Finally, the proposed metrics should be used to provide a historical context for affordability. Analyzing the metrics over time could shed light on whether rates are currently affordable by historic standards, or by comparison to other jurisdictions. Similarly, marginal increases in metrics would be easier to interpret (i.e., whether a particular increase is large or small compared to other increases) if stakeholders are aware of the distribution of marginal rate increases over time.

b. How should the Commission use affordability metrics to prioritize or design ratepayer programs?

The metrics should be used initially to identify geographic areas where a significant portion of the population faces substantial hardship due to utility costs. CalCCA notes that this does not exist today: CARE enrollment rates and local poverty levels offer potential proxies, but provide incomplete information. For example, the Commission should consider using the proposed metrics to identify geographic concentrations of customers who are experiencing substantial hardship and may thus be considered for additional rate relief programs (e.g., a "CARE+" program).

As several parties recommended in opening and reply comments on the *Administrative Law Judge's Ruling Adding Workshop Presentations to the Record and Inviting Post-Workshop Comments*, definitions and metrics used in this proceeding should be sure to highlight affordability impacts to disadvantaged communities. To this end, map layers of affordability metrics should be used in conjunction with maps of disadvantaged communities, defined according to the Disadvantaged Communities Advisory Group's Equity Framework.[12] However, since the focus of this proceeding is on affordability, we caution the Commission to use the "Poverty" score, rather than the cumulative CalEnviroScreen score, because the environmental variables included in the score may skew away from very poor communities with comparatively less pollution than other communities that may, in turn, have comparatively less poverty.

c. In which types of proceedings should the Commission assess affordability? What criteria should be used to determine if a proceeding requires an affordability assessment?

To be comprehensive, the Commission should base its affordability assessments on the cumulative impacts of all cost-causing filings, and new assessments for individual utility sectors should be required as part of Commission decisions to approve new rate requests. Proceedings should not be assessed in isolation. Once criteria for "substantial hardship," are defined, comprehensive affordability assessments across utilities should also be conducted on a quarterly basis.

III. Conclusion

[12] As stated in CalCCA's *Reply Comments in Response to the Administrative Law Judge's Ruling Adding Workshop Presentations to the Record and Inviting Post-Workshop Comments*, filed June 4, 2019, "CalCCA supports the use of this DAC definition, particularly because it includes areas where income levels are less than 80% of Area Median Income, and thus reflects regional differences in earnings. Additionally, CalCCA believes that this definition could be further improved by including census tracts within the top 25% for poverty, as measured either by CalEnviroScreen's "poverty" column, or with household income levels below the CPM poverty thresholds by county.

CalCCA appreciates the opportunity to provide these comments on the Staff Proposal. We believe that the approaches recommended here will help ensure the Commission adopts an actionable and holistic affordability framework.

Respectfully submitted,

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Dated: September 10, 2019

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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)

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October 28, 2019

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The California Community Choice Association[1] ("CalCCA") respectfully submits these comments in response to the *Administrative Law Judge's Ruling Issuing Staff Reports and Request for Comments and Reply Comments* ("ALJ Ruling") issued October 14, 2019.

I. INTRODUCTION

The 19 members of CalCCA are the operating community choice aggregators ("CCAs") and additional affiliated cities and counties interested in exploring the opportunities of community choice energy. As local government agencies, local governments, or community groups, we are keenly aware that electricity is a basic necessity in Californians' daily lives and critical to the economic and social health of the state. CalCCA's members strongly support this proceeding's aims to reduce the number of customers experiencing disconnection after

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nonpayment and to improve the reconnection processes and outcomes for customers that have been disconnected.

CalCCA supports certain parties' recommendations summarized in the Workshop Report II and reiterates many of the recommendations it has made in prior filings to this proceeding. Namely, as discussed below,

1) The reasons why focusing on communities with high disconnection rates when targeting solutions to bring down the statewide disconnection rate is necessary;
2) The importance of close coordination with community-based organizations (CBOs); and
3) The need for better CCA access to customer information including previous disconnections and future likelihood of being disconnected.

II. RESPONSES TO ALJ RULING ON WORKSHOP REPORT II

A. Sub-rules for Vulnerable Communities Must Accompany the Adoption of Any Statewide Disconnection Target

Although it is true that each IOU has unique territories with differing characteristics, CalCCA does not support setting individual targets for each IOU. The IOU territory where a customer happens to reside should not impact whether that customer is more or less likely to be disconnected. Not only has the reason for setting different disconnection targets not been substantiated by any evidence that it might be beneficial for decreasing the number of disconnection events but also, and more importantly, setting different disconnection targets would be inequitable. CalCCA supports GRID Alternatives and TURN's proposal to set a statewide disconnection target at 3.5% by 2024.[2] However, a 2024 statewide disconnection target of 3.5% would be an average of the disconnection rates across the state. This average rate would be misleading because it would hide disparities within the state. As East Bay Community Energy presented at the Workshop on July 23, 2019, certain zip codes have average disconnection rates that are much higher than the average rate of the IOU they are served by. For example, three zip codes in Oakland have an average disconnection rate greater than 15%, while PG&E's average disconnection rate is 5.4%.[3] These disparities would be hidden if California were to adopt solely an average statewide disconnection rate. For this reason, CalCCA supports implementation of not necessarily sub-targets (as PG&E points out there is no reason for communities with high disconnection rates to have an even lower target disconnection rate than 3.5%) but instead sub-rules that would focus on decreasing the disconnection rate of zip codes with the highest rates as the strategy for lowering the average rate across California.[4]

B. *Any Special Considerations in Disconnection Policy for Households with Children or Seniors Must Be Accompanied by Appropriate Protections to Prevent Abuse*

CalCCA continues to recommend that the Commission adopt solutions not only for vulnerable customers but also for customers that do not qualify for any energy assistance programs yet remain burdened by other socioeconomic factors.[5] Energy providers such as CCAs most certainly cannot relieve all the socioeconomic burdens that contribute to the root cause of disconnections but are willing to assist through the levers

[2] Workshop Report II, p. 6.
[3] See Slide 12 of "EBCE Connected Communities Pilot" presentation given on July 23, 2019.
[4] See Grid Alternatives and SCE's proposal summarized on page 8 of Workshop Report II.
[5] See recommendations in June 14, 2019 CalCCA Response to ALJ's Ruling Requesting Responses to Questions issued May 1, 2019.

we have direct control over. Innovative and comprehensive approaches to minimizing disconnection should be implemented such as the pilots discussed below and include solutions that consider establishing or increasing reserve funds for subsidies along with increased access to energy efficiency programs (e.g. inefficient refrigerator replacement for rental units).

More specifically, CalCCA agrees with Catholic Charities' suggestion that senior customers as well as families with children will need additional protections to prevent them from being disconnected. CalCCA supports Alameda County Public Health's proposal to "grant a grace period to prevent senior citizens and vulnerable customers from disconnections" because it is an effective protection that is relatively easy to implement since it would allow more time to work with seniors and families with children to develop a plan for addressing their disconnection risk (e.g. enrolling them in CARE/FERA, coordinating with CBOs to submit LIHEAP pledges, explaining how they can lower their energy usage and decrease their monthly bill, putting them on a fixed payment plan, percentage of income payment plan, or arrearage management program once implemented).[6] For any other solutions that attempt to assist as many customers facing disconnections as possible, and expand beyond only vulnerable customers, CalCCA recommends that program design to prevent misuse be considered upfront. One way to do this is to ensure that internal organization processes are robust (e.g. sufficient resources for staff, customer service training on all available programs, and training to efficiently and accurately process customers enrolling in programs). Additionally,

[6] Workshop Report II, p. 16.

alternative credit scoring methodologies could be adapted to qualify customer eligibility for certain programs.[7]

C. Information Sharing Between CCAs and IOUs Will Be Crucial for Success of Any Disconnections Programs

IOUs and CCAs share customers and the effectiveness of any disconnection program will be highly dependent on the ability of CCAs and IOUs to consistently coordinate. As discussed in CalCCA's June 14, 2019 Opening Comments, CCAs typically do not know that a customer has received a 15-day or 48-hour notice, or has been disconnected recently or in the past.[8] The only means by which a CCA can gain access to information about individual customers' disconnections history is through a formal data request to an IOU. In order for CCAs to evaluate the success of their programs and develop new ones, we need to know how frequently customers have been disconnected in the past. Additionally, to effectively be able to assist customers, CCA's must be able to continuously monitor and know exactly which customers are in danger of being disconnected. IOUs should ensure CCAs are notified of disconnection risk before a customer is disconnected. CalCCA recommends the disconnection history and 15-day

[7] See p. 27 of Vote Solar: Inclusive Solar Finance Framework, https://votesolar.org/files/1215/3394/2652/Inclusive_Solar_Finance_Framework_Report.pdf.

[8] See pp. 12-13 of CalCCA Response to *Administrative Law Judge's Ruling Requesting Responses to Questions* issued May 1, 2019.

notice information be added to the list of information currently released to CCAs on an ongoing basis under existing nondisclosure agreements with IOUs.[9]

Additionally, CalCCA supports the development of a framework for sharing customer information about payment history with third parties. CalCCA recommends the Commission develop such a framework by examining and, if necessary, modifying prior Commission Decision 12-08-045.[10] A modification to allow energy providers to work more effectively with CBOs on reducing disconnections would aid progress towards California's 2024 disconnection target. Customer privacy rules do not explicitly allow sharing of information on customer payment history. Out of an abundance of caution, energy providers thus may be disinclined to share with other organizations any information on customer payment history, including the fact that individual customers have had difficulty making payments. However, a key component of disconnection reduction efforts will be targeted referrals of individual customers to CBOs. Currently, certain customer data may be shared for the purpose of implementation or evaluation of DR/EE/Energy Management Programs. CalCCA recommends Decision 12-08-045 be modified to state that customer information related to payment history may be shared for the purpose of enrollment or implementation of Commission programs for low-income customers, such as CARE/FERA, DAC-SASH, and DAC-GT/CSGT. Without this change, CCAs will only be able to enroll customers in programs we administer and for which we do outreach directly, or, must request permission from customers individually

[9] Each IOU has an electric schedule that specifics the information provided to CCAs under NDA. These schedules are referred to as PG&E Electric Schedule E-CCAINFO, SCE Schedule CCA-INFO, and SDG&E Schedule CCA-INFO.

[10] Issued August 23, 2012, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M026/K531/26531585.PDF.

before sharing their information with CBOs, which is an inefficient method of addressing an already complex outreach process.

D. The Same New Program Pilot Proposals Must be Deployed in Each IOU's Service Territory

Parties presented numerous different pilot ideas and proposals for how to go about implementing pilots. CalCCA recommends that the same pilots developed be deployed in each IOU's service territory. Standardizing pilots across different IOU territories will allow the Commission to gather meaningful data on what works to reduce the disconnection rate and what does not. Additionally, CalCCA recommends, as emphasized in CalCCA's June 14, 2019 Opening Comments and July 1, 2019 Reply Comments to the May 1, 2019 *Ruling Requesting Responses to Questions*, close coordination with CBOs. Such coordination will be imperative to successfully determine the specifics of the pilots (e.g. how they should be structured, requirements for eligibility, enrollment process) and for successful outreach to ensure customers are made aware of the programs available. The October 25, 2019 webinar on arrearage management programs presented by Eversource, further exemplified this point when explaining that the Northeastern utility depends heavily on its community partners to successfully enroll customers in their programs.[11]

The specific pilot proposals CalCCA supports presented during this past summer's workshops include PG&E and SoCalGas' proposal to eliminate re-establishment deposits and reconnections fees for CARE and FERA customers and

[11] Penni McLean-Conner presentation on the success of NuStart, the AMP at Eversource.

update utility websites so that customers can understand IOU disconnection policies, relationship with CCAs, CBOs, and LIHEAP providers.[12] Part of this proposal effectuates CalCCA's recommendations in June 14, 2019 comments that deposits make disconnections less likely and make it harder for customers to regain utility service, and should at a minimum be eliminated for CARE, FERA, and Medical Baseline customers. CalCCA also supports TURN's proposal for both AMP and PIPPs to be made available in separate pilots. Allowing AMPs and PIPPs to be tested separately will allow the Commission to determine the performance of each independently of each other.

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,

__*/s/ Irene Moosen*___________

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[12] Workshop Report, p. 22.

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Although it is true that each IOU has unique territories with differing characteristics, CalCCA does not support setting individual targets for each IOU. The IOU territory where a customer happens to reside should not impact whether that customer is more or less likely to be disconnected. Not only has the reason for setting different disconnection targets not been substantiated by any evidence that it might be beneficial for decreasing the number of disconnection events but also, and more importantly, setting different disconnection targets would be inequitable. CalCCA supports GRID Alternatives and TURN's proposal to set a statewide disconnection target at 3.5% by 2024.[2] However, a 2024 statewide disconnection target of 3.5% would be an average of the disconnection rates across the state. This average rate would be misleading because it would hide disparities within the state. As East Bay Community Energy presented at the Workshop on July 23, 2019, certain zip codes have average disconnection rates that are much higher than the average rate of the IOU they are served by. For example, three zip codes in Oakland have an average disconnection rate greater than 15%, while PG&E's average disconnection rate is 5.4%.[3] These disparities would be hidden if California were to adopt solely an average statewide disconnection rate. For this reason, CalCCA supports implementation of not necessarily sub-targets (as PG&E points out there is no reason for communities with high disconnection rates to have an even lower target disconnection rate than 3.5%) but instead sub-rules that would focus on decreasing the disconnection rate of zip codes with the highest rates as the strategy for lowering the average rate across California.[4]

B. *Any Special Considerations in Disconnection Policy for Households with Children or Seniors Must Be Accompanied by Appropriate Protections to Prevent Abuse*

CalCCA continues to recommend that the Commission adopt solutions not only for vulnerable customers but also for customers that do not qualify for any energy assistance programs yet remain burdened by other socioeconomic factors.[5] Energy providers such as CCAs most certainly cannot relieve all the socioeconomic burdens that contribute to the root cause of disconnections but are willing to assist through the levers

[2] Workshop Report II, p. 6.
[3] See Slide 12 of "EBCE Connected Communities Pilot" presentation given on July 23, 2019.
[4] See Grid Alternatives and SCE's proposal summarized on page 8 of Workshop Report II.
[5] See recommendations in June 14, 2019 CalCCA Response to ALJ's Ruling Requesting Responses to Questions issued May 1, 2019.

we have direct control over. Innovative and comprehensive approaches to minimizing disconnection should be implemented such as the pilots discussed below and include solutions that consider establishing or increasing reserve funds for subsidies along with increased access to energy efficiency programs (e.g. inefficient refrigerator replacement for rental units).

More specifically, CalCCA agrees with Catholic Charities' suggestion that senior customers as well as families with children will need additional protections to prevent them from being disconnected. CalCCA supports Alameda County Public Health's proposal to "grant a grace period to prevent senior citizens and vulnerable customers from disconnections" because it is an effective protection that is relatively easy to implement since it would allow more time to work with seniors and families with children to develop a plan for addressing their disconnection risk (e.g. enrolling them in CARE/FERA, coordinating with CBOs to submit LIHEAP pledges, explaining how they can lower their energy usage and decrease their monthly bill, putting them on a fixed payment plan, percentage of income payment plan, or arrearage management program once implemented).[6] For any other solutions that attempt to assist as many customers facing disconnections as possible, and expand beyond only vulnerable customers, CalCCA recommends that program design to prevent misuse be considered upfront. One way to do this is to ensure that internal organization processes are robust (e.g. sufficient resources for staff, customer service training on all available programs, and training to efficiently and accurately process customers enrolling in programs). Additionally,

[6] Workshop Report II, p. 16.

alternative credit scoring methodologies could be adapted to qualify customer eligibility for certain programs.[7]

C. *Information Sharing Between CCAs and IOUs Will Be Crucial for Success of Any Disconnections Programs*

IOUs and CCAs share customers and the effectiveness of any disconnection program will be highly dependent on the ability of CCAs and IOUs to consistently coordinate. As discussed in CalCCA's June 14, 2019 Opening Comments, CCAs typically do not know that a customer has received a 15-day or 48-hour notice, or has been disconnected recently or in the past.[8] The only means by which a CCA can gain access to information about individual customers' disconnections history is through a formal data request to an IOU. In order for CCAs to evaluate the success of their programs and develop new ones, we need to know how frequently customers have been disconnected in the past. Additionally, to effectively be able to assist customers, CCA's must be able to continuously monitor and know exactly which customers are in danger of being disconnected. IOUs should ensure CCAs are notified of disconnection risk before a customer is disconnected. CalCCA recommends the disconnection history and 15-day

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[7] See p. 27 of Vote Solar: Inclusive Solar Finance Framework, https://votesolar.org/files/1215/3394/2652/Inclusive_Solar_Finance_Framework_Report.pdf.

[8] See pp. 12-13 of CalCCA Response to *Administrative Law Judge's Ruling Requesting Responses to Questions* issued May 1, 2019.

notice information be added to the list of information currently released to CCAs on an ongoing basis under existing nondisclosure agreements with IOUs.[9]

Additionally, CalCCA supports the development of a framework for sharing customer information about payment history with third parties. CalCCA recommends the Commission develop such a framework by examining and, if necessary, modifying prior Commission Decision 12-08-045.[10] A modification to allow energy providers to work more effectively with CBOs on reducing disconnections would aid progress towards California's 2024 disconnection target. Customer privacy rules do not explicitly allow sharing of information on customer payment history. Out of an abundance of caution, energy providers thus may be disinclined to share with other organizations any information on customer payment history, including the fact that individual customers have had difficulty making payments. However, a key component of disconnection reduction efforts will be targeted referrals of individual customers to CBOs. Currently, certain customer data may be shared for the purpose of implementation or evaluation of DR/EE/Energy Management Programs. CalCCA recommends Decision 12-08-045 be modified to state that customer information related to payment history may be shared for the purpose of enrollment or implementation of Commission programs for low-income customers, such as CARE/FERA, DAC-SASH, and DAC-GT/CSGT. Without this change, CCAs will only be able to enroll customers in programs we administer and for which we do outreach directly, or, must request permission from customers individually

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[9] Each IOU has an electric schedule that specifics the information provided to CCAs under NDA. These schedules are referred to as PG&E Electric Schedule E-CCAINFO, SCE Schedule CCA-INFO, and SDG&E Schedule CCA-INFO.
[10] Issued August 23, 2012, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M026/K531/26531585.PDF.

before sharing their information with CBOs, which is an inefficient method of addressing an already complex outreach process.

D. The Same New Program Pilot Proposals Must be Deployed in Each IOU's Service Territory

Parties presented numerous different pilot ideas and proposals for how to go about implementing pilots. CalCCA recommends that the same pilots developed be deployed in each IOU's service territory. Standardizing pilots across different IOU territories will allow the Commission to gather meaningful data on what works to reduce the disconnection rate and what does not. Additionally, CalCCA recommends, as emphasized in CalCCA's June 14, 2019 Opening Comments and July 1, 2019 Reply Comments to the May 1, 2019 *Ruling Requesting Responses to Questions*, close coordination with CBOs. Such coordination will be imperative to successfully determine the specifics of the pilots (e.g. how they should be structured, requirements for eligibility, enrollment process) and for successful outreach to ensure customers are made aware of the programs available. The October 25, 2019 webinar on arrearage management programs presented by Eversource, further exemplified this point when explaining that the Northeastern utility depends heavily on its community partners to successfully enroll customers in their programs.[11]

The specific pilot proposals CalCCA supports presented during this past summer's workshops include PG&E and SoCalGas' proposal to eliminate re-establishment deposits and reconnections fees for CARE and FERA customers and

[11] Penni McLean-Conner presentation on the success of NuStart, the AMP at Eversource.

update utility websites so that customers can understand IOU disconnection policies, relationship with CCAs, CBOs, and LIHEAP providers.[12] Part of this proposal effectuates CalCCA's recommendations in June 14, 2019 comments that deposits make disconnections less likely and make it harder for customers to regain utility service, and should at a minimum be eliminated for CARE, FERA, and Medical Baseline customers. CalCCA also supports TURN's proposal for both AMP and PIPPs to be made available in separate pilots. Allowing AMPs and PIPPs to be tested separately will allow the Commission to determine the performance of each independently of each other.

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,

__*/s/ Irene Moosen*___________

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Dated: October 28, 2019

[12] Workshop Report, p. 22.

Stakeholder Comments Template

Hybrid Resources Initiative: Straw Proposal

This template has been created for submission of stakeholder comments on the **Hybrid Resources Initiative, Straw Proposal** that was held on October 3, 2019. The meeting material and other information related to this initiative may be found on the initiative webpage at:
http://www.caiso.com/informed/Pages/StakeholderProcesses/HybridResources.aspx

Upon completion of this template, please submit it to initiativecomments@caiso.com. Submissions are requested by close of business on October 21, 2019**.**

Submitted by	Organization	Date Submitted
Irene Moosen, 415-587-7343	*California Community Choice Association*[1]	*October 21, 2019*

Please provide your organization's comments on the following topics and indicate your orginzation's position on the topics below (Support, Support with caveats, Oppose, or Oppose with caveats). Please provide examples and support for your positions in your responses as applicable.

California Community Choice Association (CalCCA) appreciates the opportunity to comment on the Hybrid Resources Initiative, Straw Proposal ("Straw Proposal") discussed during the October 3, 2019 stakeholder meeting. CalCCA members are pursuing hybrid resources and are keenly interested in developing rules to facilitate efficient utilization of the these resources.

1. Hybrid Resource Definition

Please provide your organization's feedback on the Hybrid Resource Definition as described in the straw proposal.

[1] California Community Choice Association represents local government Community Choice Aggregation electricity providers in California members, including Apple Valley Choice Energy, CleanPowerSF, Clean Power Alliance, East Bay Community Energy, King City Community Power, Lancaster Choice Energy, MCE, Monterey Bay Community Power, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Jacinto Power, San Jose Clean Energy, Silicon Valley Clean Energy, Solana Energy Alliance, Sonoma Clean Power, Valley Clean Energy.

CAISO is proposing to distinguish hybrid resources from other co-located resources based on whether the resources participate in the CAISO markets using a single Resource ID or multiple Resource IDs:

> "Hybrid Resources are a combination of multiple generation technologies that are physically and electronically controlled by a single owner/operator and Scheduling Coordinator and behind a single point of interconnection ("POI") that participates in the CAISO markets as a single resource with a single market resource ID." [Straw Proposal at p. 7]

Resources with a single Resource ID will be considered Hybrid Resources, while resources with multiple Resource IDs will be considered Co-located Resources. CalCCA supports this definition, though it does have comments about CAISO's proposed forecasting and metering requirements associated with each type of resource, as described further below.

2. Hybrid Resources Business Drivers and Use Cases

Please provide your organization's feedback on the Hybrid Resources Business Drivers and Use Cases described in the straw proposal.

CalCCA agrees that the use cases for Hybrid Resources and Co-located Resources may overlap. Because of this, it is important to ensure that both configurations can be accommodated and that any differential treatment be applied only where necessary. For example, CalCCA urges CAISO not to limit Co-located Resource storage charging only from the grid; that is, allow Co-located Resource VER charging as described in Section 4 below. Similarly, given appropriate metering, CAISO should allow Hybrid Resources to be charged from the grid to the extent desired by each project operator so that project and grid operations can be optimized.

CalCCA members are pursuing both Hybrid Resources and Co-located Resources to meet a variety of business uses, including time shifting of generation to meet loads during more valuable periods (e.g., during the post-peak hours when solar generation drops and net loads increase). Their ability to utilize these resources to respond to changing market conditions and grid operational needs will be affected by the policies implemented as a result of this initiative. CalCCA urges the CAISO to ensure that the adopted rules are flexible so that the value of the combined resources can be maximized.

3. Forecasting

Please provide your organization's feedback on the forecasting topic as described in the straw proposal.

CAISO is proposing to provide forecasting only for Co-located Variable Energy Resources (VER), and to not provide forecasting for Hybrid Resources. While CalCCA appreciates that with a single Resource ID it might not be possible for CAISO to accurately forecast combined Hybrid Resource production, CalCCA urges CAISO to consider providing forecasting services, as requested by the resource's Scheduling Coordinator, for the VER component of the Hybrid Resource, as long as appropriate metering and meteorologic data were provided to the CAISO and the resource paid the VER forecast fee. Doing so would allow the Hybrid Resource owner to benefit from the CAISO's access to specialized VER forecasting expertise, while the CAISO would benefit from access to more data to improve its forecasting, improved operational situational awareness, and broader sharing of forecasting costs. The resource owner could incorporate the CAISO forecast information into its combined forecast for the Hybrid Resource (or use its own VER forecast), which it would provide to CAISO for CAISO to use, in conjunction with storage State of Charge, to develop the upper economic limit for dispatch targets.

CalCCA urges CAISO to identify in more detail what its concerns may be about potential "strategic use" of the Hybrid Resource forecast, any potential adverse consequences for the CAISO markets, potential mitigation measures, and alternative approaches for determining Hybrid Resource potential that could address the CAISO's strategic use concerns. For example, if CAISO had VER resource visibility and access either to its own or a certified VER forecast, along with storage state of charge visibility, would CAISO still have strategic use concerns?

4. Markets and Systems

Please provide your organization's feedback on the markets and systems topic as described in the straw proposal.

CalCCA supports using the Hybrid Resource forecast (or potentially the resource's Bid, as suggested by PG&E) to establish the upper economic limit for the resource.

For Co-located Resources, CalCCA supports CAISO's proposal to limit the combined output to the Point of Interconnection rights.

CalCCA urges CAISO to consider developing functionality to allow Co-located storage resources to be charged, either partially or exclusively, from the Co-located VER resource, perhaps via a Self-Schedule from the VER resource and corresponding storage resource Self-Scheduling and Bidding. This would allow the Co-located Resource owner to mitigate inverter and POI limitations, maximize preferred resource production, optimize ITC value, and continue to participate in the Eligible Intermittent Resource program, while providing CAISO with access to any net VER output and the storage output. CalCCA believes that there may be valid reasons for a resource owner to prefer a single Resource ID (Hybrid Resource) or multiple Resource IDs (Co-located Resource), However, both VER charging and/or grid charging should be allowed for both Hybrid Resource and Co-located resource configurations pursuant to preferences expressed in the Resource Bids.

5. Ancillary Services

Please provide your organization's feedback on the ancillary services topic as described in the straw proposal. (Please indicate Support, Support with caveats, Oppose, or Oppose with caveats)

For the VER portion of both Hybrid Resources and Co-located Resources, CalCCA supports the use of the VER forecast to determine the potential Ancillary Services Capacity from VER resources. This can then be used in conjunction with the storage resource state of charge, to determine the A/S potential for Hybrid Resources.

6. Metering and Telemetry

Please provide your organization's feedback on the metering and telemetry topic as described in the straw proposal.

CalCCA urges CAISO to continue to facilitate certification of DC meters to provide the greatest amount of flexibility and enhanced visiability of the various components of Hybrid Resources and Co-located Resources.

CalCCA supports CAISO's efforts to ensure that the available metering configurations will allow CAISO to report RPS production accurately.

7. Resource Adequacy

Please provide your organization's position on the Resource Adequacy topic as described in the straw proposal.

CalCCA supports CAISO's proposed interim methodology for setting Hybrid Resource RA Net Qualifying Capability using the VER Effective Load Carrying Capacity (ELCC) plus Storage NQC, subject to deliverability and interconnection POI rights. This interim approach would treat Hybrid Resources and Co-Located Resources similarly for purposes of RA NQC, which would reflect underlying physical capabilities of similar Hybrid and Co-located resources.

Some parties at the October 3 stakeholder meeting argued that it isn't possible to get the full VER output plus the full storage output. CalCCA disagrees. As an engineering matter, it is entirely possible to obtain the full output of both the VER resource (which itself can be excess of the ELCC) and the storage resource during the periods when both resources are needed. The ELCC approach significantly already discounts the VER resource capabilities and doesn't consider how VER resources will be operated in conjunction with storage resources. CalCCA believes that CAISO's proposal is appropriate as an interim measure. Any modifications can be made to reflect real-world experience. If supported by data identifying significant differences between the performance of Hybrid Resources and Co-located Resources, CAISO could propose treating these resources differently.

CalCCA supports having separate Must Offer Obligations (MOO) for Co-located Resources. For Hybrid Resources, CalCCA supports CAISO's proposal for the MOO to be based on the self-provided, combined resource forecast.

Additional comments

Please offer any other feedback your organization would like to provide on the Hybrid Resources Initiative.

Stakeholder Comments Template

Resource Adequacy Enhancement Initiative: Second Revised Straw Proposal

This template has been created for submission of stakeholder comments on the **Resource Adequacy Enhancements Initiative, Second Revised Straw Proposal** that was held on October 9, 2019. The meeting material and other information related to this initiative may be found on the initiative webpage at: http://www.caiso.com/informed/Pages/StakeholderProcesses/ResourceAdequacyEnhancements.aspx

Upon completion of this template, please submit it to initiativecomments@caiso.com. Submissions are requested by close of business on October 24, 2019**.**

Submitted by	**Organization**	**Date Submitted**
Irene Moosen, 415-587-7343 *Director, Regulatory Affairs* *irene@cal-cca.org*	*California Community Choice Association*[1]	*October 30, 2019*

Please provide your organization's comments on the following topics. When applicable, please indicate your orginization's position on the topics below (Support, Support with caveats, Oppose, or Oppose with caveats). Please provide examples and support for your positions in your responses.

California Community Choice Association (CalCCA) appreciates the opportunity to comment on the Resource Adequacy Enhancements Initiative, Second Revised Straw Proposal ("2nd Revised Straw Proposal") discussed during the October 9, 2019 stakeholder meeting. CalCCA members support CAISO's efforts to make significant improvements to the Resource Adequacy (RA) rules. As California continues its transition to a cleaner fleet of resources, CAISO must ensure that it has access to sufficient resources to continue to reliably operate the grid. CCAs are interested in an efficient and effective Resource Adequacy process as the entities that serve a significant and increasing share of CAISO load.

[1] California Community Choice Association represents local government Community Choice Aggregation electricity providers in California members, including Apple Valley Choice Energy, CleanPowerSF, Clean Power Alliance, East Bay Community Energy, King City Community Power, Lancaster Choice Energy, MCE, Monterey Bay Community Power, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Jacinto Power, San Jose Clean Energy, Silicon Valley Clean Energy, Solana Energy Alliance, Sonoma Clean Power, Valley Clean Energy.

System Resource Adequacy

1. **Determining System RA Requirements**

   Please provide your organization's feedback on the System RA Requirements proposal as described in the second revised straw proposal.

   CalCCA supports CAISO's proposal to consider both Net Qualifying Capacity (NQC) and Unforced Capacity (UCAP) values in its RA accounting. In general, each resource would make its NQC available to CAISO, but only receive RA credit for its UCAP, reflecting adjustments for historical forced outages. Conceptually, CalCCA agrees with CAISO's proposal to set the UCAP requirement at a minimum of 106% of the forecasted 1-in-2 year peak load (i.e., forecast load plus operating reserves), plus any additional capacity needed to account for forecast error.

   It will be important to have a clear analytical process to determine the amount of forecast error. Otherwise, the CAISO risks having an RA target that overstates CAISO's resource needs, leading to unnecessary costs, or having one that understates the needs, leading to reduced reliability and potential shortage costs. CalCCA supports applying a prudent planning approach to develop the forecast error margin. A simple method of considering forecast error could be to calculate the amounts of RA required to meet the one-in-five year or one-in-ten year forecasts. However, these methods do not capture the complete set of reliability issues identified by the CAISO including the post-peak energy availability. In order to capture reliability concerns beyond the peak hour in the RA analysis, the CAISO can perform a Loss of Load Expectation (LOLE) analysis that assumes 100% generation availability to identify the additional margin needed to account for forecast error and yield an LOLE of 0.1 days per year.Since UCAP will directly account for forced outages and the maintenance outage process will schedule maintenance during periods when resources are not needed, 100% availability will not result in double counting.

2. **Forced Outage Rates Data and RA Capacity Counting**

   Please provide your organization's feedback on the Forced Outage Rates and RA Capacity Counting and Forced Outage Rate Data topics as described in the second revised straw proposal.

   CalCCA supports the CAISO proposal to calculate UCAP values for all resource types that do not rely on the CPUC's Effective Load Carrying Capability (ELCC) methodology for determining Qualifying Capacity (QC) values and, for resources with ELCC values, to use the ELCC value as the UCAP value.

   CalCCA appreciates the CAISO's efforts to attempt to analyze historical forced outage data so that parties may better understand how a UCAP approach might be applied.

Based on the discussion during the stakeholder meeting, it appears that the available forced outage data potentially overstates the level of forced outages, since it is reported on a daily basis. That is, all outages appear to be treated as lasting an entire day. Given the critical role that forced outage rates play in determining each resource's UCAP, and the collective impact on the reliability of the RA fleet, it is extremely important to ensure that the forced outage rates are accurate.

Given the potential challenges for collecting forced outage data, CalCCA suggests the CAISO consider an alternative approach for determining forced outages. In place of generator Generating Availability Data System (GADS) data, CAISO could use historical energy and capacity Bids or Self-Schedules. The implied forced outage rate would be determined by adding approved maintenance outage capacity to the Bid/Self-Scheduled capacity and then subtracting the total from the product of the generator's NQC x 8760 hours. This approach could simplify the data collection, since CAISO would be able to use Bid data, supplemented by approved outage data, to make the calculation, and would not need to process the multifaceted forced outage data. Any reduction in output not part of an approved maintenance outage would be treated as a forced outage for purposes of calculating UCAP. The UCAP amounts would thus represent capacity that is actually available to CAISO, after taking into consideration approved maintenance outages. For new resources or resources for which appropriate Bid or Self-Schedule data is not available proxy values could be used for an appropriate transition period until actual values are developed.

CalCCA supports using resource-specific forced outage rates and incorporating a weighting method that places more weight on the most recent year's performance and less weight on more historic periods in determining a resource's UCAP values. The CAISO's initial proposal to use 50% weight for the most recent annual forced outage rate, 30% weight on the second annual forced outage rate period, and 20% weight on the third annual forced outage rate period appears to be reasonable. Given the possibility that historical forced outage data may not accurately reflect actual forced outages under the proposed UCAP approach, CalCCA recommends that CAISO consider putting more weight on the early year data once that data begins to reflect actual forced outages under the UCAP approach (e.g., 70/20/10 after one year of data has been collected, 60/30/10 after two years' data has been collected, then 50/30/20 thereafter).

3. Proposed Forced Outage Rate Assessment Interval

Please provide your organization's feedback on the Proposed Forced Outage Rate Assessment Interval topic as described in the second revised straw proposal.

CalCCA notes that CAISO's data presented suggests that forced outages do not appear to vary based on the season or based on relatively high levels of load. Thus, it may not be warranted to differentiate forced outages by season or by time of use.

Instead, CAISO should consider applying a single forced outage rate for each resource for an entire year, unless further analysis indicates seasonal variation.

4. System RA Showings and Sufficiency Testing

Please provide your organization's feedback on the System RA Showings and Sufficiency Testing proposal as described in the second revised straw proposal.

CalCCA is generally supportive of CAISO's proposal to conduct both an individual deficiency test of LSE shown UCAP and a portfolio deficiency test that models all LSEs' shown UCAP (either as random draws simulating forced outages based on individual resource forced outage rates, or scaled generation and load using UCAP values, if CAISO is unable to perform stochastic simulations due to time constraints). CalCCA is concerned, however, that the proposed portfolio deficiency test might not be transparent nor provide the appropriate signals for LSEs to act to minimize the potential for CAISO backstop procurement. CalCCA urges CAISO to explore ways to provide as much information to market participants as far in advance as possible to anticipate potential deficiencies in time to act to avoid such deficiencies. For example, rather than wait until CAISO has visibility for 100% of the RA resources needed to meet the target UCAP requirement, CAISO could run an indicative annual assessment that derates the system loads and available transmission to match the amount of UCAP known at the time of the study (e.g., 90%); this analysis could be similar to the approach used in the CRR Allocation process. CalCCA also encourages CAISO to extend the analysis beyond a single year by supplementing known commited RA resources, such as those shown or acquired by the proposed RA-Central Procurement Entity, with an assumption that the other RA resources from the prompt year would be made available for subsequent years, with adjustments for known retirements. This could provide a useful indication of potential future year deficiencies, particularly for local resources and for resources needed to meet deficiencies in hours other than the system peak hour.

CalCCA opposes the proposed LSE RA showing incentive, in which CAISO would charge short LSEs a penalty and distribute collected proceeds to long LSEs. We are concerned that such penalties could distort the bilateral RA markets, particularly in cases where suppliers have market power. Parties that fail to meet their RA requirements will be at risk of being allocated CAISO backstop procurement costs resulting from their deficiencies, in addition to being exposed to potential high energy market prices. CalCCA also notes that if the RA-CPE proposal supported by CalCCA is implemented, all of the CPUC jurisdictional LSE RA requirements would be met on a three year forward basis by individual LSEs and the RA-CPE without any penalty structure.

5. **Must Offer Obligation and Bid Insertion Modifications**

Please provide your organization's feedback on the Must Offer Obligation and Bid Insertion Modifications proposal as described in the second revised straw proposal.

CalCCA supports setting Must Offer Obligations (MOO) at NQC (rather than UCAP). Doing so appropriately makes the full capacity of the resource available to CAISO, except during outages.

CalCCA supports 24 by 7 MOO into the Day-Ahead Market for most resources and removal of blanket 24 by 7 real-time MOO, since CAISO's proposed imbalance reserves will cover real-time uncertainties. While some parties at the meeting raised concerns about relieving resources capable of real-time operations from the RT MOO, CalCCA notes that requiring all RA resources to be dispatchable in real-time creates costs that ultimately are borne by consumers. For example, if an RA resource that isn't committed in the Day-Ahead Market is required to bid into the real-time market (RTM,) the operator of the resource will need to ensure appropriate staff are available to respond to RTM dispatch instructions. But the imbalance reserve requirement proposed in the Day Ahead Market Enhancements Initiative should provide CAISO access to sufficient RT dispatchable resources to operate the grid reliably and efficiently. The imbalance reserve requirement can be adjusted as necessary to ensure that CAISO has access to sufficient resources in the RTM.

6. **Planned Outage Process Enhancements**

Please provide your organization's feedback on the Planned Outage Process Enhancements proposal as described in the second revised straw proposal.

CalCCA supports CAISO's proposed modifications to the planned outage process, but has some concerns about potentially providing incentives for resource owners to withhold capacity to cover maintenance outages that may not be approved by CAISO. Providing generators the opportunity to self-provide resources for maintenance outages appears to create inefficiencies and may contribute to the exercise of market power. It is less efficient for resource owners to individually hold back capacity to cover potentially-denied maintenance outages, than to rely on the collective resources to cover these outages. CAISO presented analysis demonstrating very little replacement capacity has been provided to address RA Forced Outages. CalCCA believes this information suggests that rather than allowing or requiring resource substitution for maintenance outages, if CAISO's analysis shows it can reliably serve load with the remaining available resources, then the requested outage should be allowed. Maintenance outages that are not approved would be treated as forced outages, which will affect future UCAP values. If necessary, CAISO could use its CPM authority to obtain capacity to cover resources on outage.

CalCCA supports minimizing the frequency of cancelling previously-approved maintenance outages, since this leads to increased costs that ultimately are borne by consumers.

7. **RA Imports Provisions**

Please provide your organization's feedback on the RA Imports Provisions proposal as described in the second revised straw proposal.

CalCCA notes that the recent CPUC decision on import RA (D.19.10.021) may force the CAISO to reconsider how it proposes to deal with import RA. Having two different rules within the CAISO for which RA imports can count will likely create problems. CalCCA prefers the CAISO's proposed solutions to those that were included in the CPUC decision and has filed a Application for Rehearing and a Petition for Stay in that docket. CalCCA supports CAISO's proposal to require specification of the Source Balancing Authority Area (BAA) for all RA imports on monthly showings. This approach will address potential double counting issues and ensure that the RA resource is supported by the exporting BAA.

CalCCA supports the proposed requirement that LSEs (and resource SCs) provide documentation to reflect unspecified imports being used to meet RA requirements have physical capacity with operating reserves behind them and firm transmission. Documentation can be contract language or an attestation from the import provider that confirms the RA import is supported by physical capacity and operating reserves..

CalCCA supports not requiring Imports to submit real-time bids, since that would require that transmission capacity be set-aside that otherwise could be made available to import lower cost resources. This would have a negative impact on market efficiency.

CalCCA strongly supports the proposed separate process to address MIC provisions necessary to address recently identified 2021 RA year capacity shortfall and potential adoption of the multi-year RA framework proposed in the RA Central Procurement Entity settlement pending before the CPUC.

Flexible Resource Adequacy

8. **Identifying Flexible Capacity Needs and Requirements**

Please provide your organization's feedback on the Identifying Flexible Capacity Needs and Requirements topic as described in the second revised straw proposal.

CalCCA agrees with the CAISO's proposal to simplify the flexible capacity requirements and as discussed below in response to #9

9. **Setting Flexible RA Requirements**

Please provide your organization’s feedback on the Setting Flexible RA Requirements topic as described in the second revised straw proposal.

CalCCA supports CAISO’s proposal to set the Flexible ramping requirement based on uncertainty between Day-Ahead Market and RTM, instead of based on three-hour net load ramp. CAISO should ensure, however, that it will have access to sufficient resources day ahead to meet the net load ramping needs. Assuming that this is the case, the CAISO can focus the flexible requirement on identifying the resources that are required to address the uncertainty between the DAM and RTM.

10. Establishing Flexible RA Counting Rules: Effective Flexible Capacity Values and Eligibility

Please provide your organization’s feedback on the Establishing Flexible RA Counting Rules: Effective Flexible Capacity Values and Eligibility topic as described in the second revised straw proposal.

CalCCA supports CAISO’s proposal to simplify the flexible counting criteria, and to recognize that imports are an important source of flexible capacity and should be eligible. CAISO must, however, recognize that the recent CPUC decision on imported RA effectly removes non-resource specific import RA from providing any flexibility since it must be self scheduled into the CAISO. CAISO’s proposed, high level eligibility criteria appear to be reasonable:

- Either be a non-use limited resource or a use-limited resource with a use limitation CAISO can model in its energy market or through an opportunity cost adder
- Not be a Conditionally Available Resource
- Be dispatchable in at least 15 minute increments (including imports)
- Not be a regulation energy management resource

CalCCA agrees with CAISO that flexible counting rules for solar should address the unique characteristics of these resources. CAISO should identify the amounts of solar flexibility that can be available and utilized for the periods when these resources are expected to be available. CalCCA looks forward to working with CAISO and other stakeholders to develop appropriate solar flexible counting rules.

CalCCA supports CAISO’s proposal to count non-generating resources’ (NGR) Effective Flexible Capacity (EFC) based on the resource’s ability to provide generation (positive and negative) over a fifteen minute period. This allows NGR resources to potentially receive EFC values that include their full charge and discharge ranges.

11. Flexible RA Allocations, Showings, and Sufficiency Tests

Please provide your organization's feedback on the Flexible RA Allocations, Showings, and Sufficiency Tests topic as described in the second revised straw proposal.

CalCCA opposes allocation of the flexible requirement based on each LRAs' proportional share of peak load, and MWs of wind and solar. CAISO instead should identify the contribution to the uncertainty between DAM and RTM of each of load, wind and solar. It should then allocate the requirement based on each LRA's share of load, wind and solar. This approach will better align cost allocation with cost causation.

12. Flexible RA Must Offer Obligation Modifications

Please provide your organization's feedback on the Flexible RA Must Offer Obligation Modifications topic as described in the second revised straw proposal.

No comments at this time.

Local Resource Adequacy

13. UCAP for Local RA

Please provide your organization's feedback on the UCAP for Local RA topic as described in the second revised straw proposal.

CalCCA supports Option 1: Convert LCRs into UCAP after the study process. CalCCA agrees that CAISO should continue to determine the need using NQC, but then state the requirement in terms of equivalent UCAP amounts (e.g., if the local need is 1000 MW and the weighted average forced outage rate of the resources CAISO identified when setting the need is 10%, the equivalent UCAP requirement would be 900 MW). This should result in the same resources (and associated NQC) as would be determined using the current LCR technical study approach.

Additional comments

Please offer any other feedback your organization would like to provide on the RA Enhancements Initiative.

CALCCA
ADVANCING LOCAL ENERGY CHOICE

Neil Raffan
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Energy Division
California Public Utilities Commission
and
Parties to R.16-02-007

VIA E-mail

October 29, 2019

Dear IRP Modeling Group,

California Community Choice Association (CalCCA) submits these informal comments in response to the California Public Utilities Commission (CPUC) Energy Division's (ED) request, dated October 22, 2019 for informal comments on the CPUC staff-proposed methodology for 2019 IRP Resource-to-Busbar mapping. For questions, comments, and communications, please contact Irene Moosen at irene@cal-cca.org.

I. INTRODUCTION AND SUMMARY

CalCCA welcomes the opportunity to engage and help the Commission develop a more robust process for resource-to-busbar mapping ("busbar mapping") that is expected to refine the geographically coarse portfolios produced in the CPUC's Integrated Resource Plan (IRP) proceeding, into plausible network modeling locations for electrical analysis in the California Independent System Operator's (CAISO) annual Transmission Planning Process (TPP). In that spirit, we offer the following recommendations to improve the process that involves meaningful stakeholder participation.

II. TRANSMISSION METHODOLOGIES SHOULD INCORPORATE CAISO'S MODIFIED TRANSMISSION CONSTRAINT METHODOLOGY

Energy Division should update its treatment of transmission constraints to reflect CAISO's most recent deliverability methodology. In its recent review of deliverability assessment methodologies, CAISO has proposed new study scenarios that would align load levels with intermittent generation output.[1] The CAISO-proposed new study approach recognizes that, with a diverse grid, the peak reliability need is offset by the generation profiles under certain renewable conditions and as a result significantly more of the resources are deliverable. Thus, this implementation of the revised methodology would result in accommodating more full capacity deliverability status (FCDS) resources in a given transmission area than under the existing methodology without triggering the need for additional transmission upgrades. The CAISO has found that several upgrades identified using the current methodology would not be needed under the new methodology.[2]

[1] See http://www.caiso.com/Documents/DraftFinalProposal-GenerationDeliverabilityAssessment.pdf
[2] CAISO Generation Deliverability Assessment Methodology Draft Final Proposal Stakeholder Call, October 4, 2019, p.29 (See http://www.caiso.com/Documents/Presentation-GenerationDeliverabilityAssessmentDraftFinalProposal.pdf)

Implementing this proposed methodology should be relatively simple to implement, because the CAISO would simply provide updated values to the CPUC, allowing easy implementation inside of RESOLVE. Applying this new methodology in this IRP cycle is appropriate, because the CAISO seems to be targeting implementation beginning January 2020.[3] Therefore, **CalCCA recommends that the CPUC should use CAISO's transmission inputs estimates based upon the revised deliverability assessment methodology**. In doing so, some renewable buildout areas are likely to see significant changes in the deliverable numbers.

III. RESPONSES TO THE CPUC'S QUESTIONS FOR STAKEHOLDERS

Below CalCCA provides a response to only one question included in the busbar mapping methodology document and reserves the right to address the remaining questions in its formal comments on draft mapping results to be attached to the Ruling on Proposed Reference System Portfolio and informal comments on the draft mapping of TPP Sensitivity Case(s).

i. If storage was to be added to this methodology for 2019 IRP portfolios, how would it need to be revised, noting that current IRP modeling does not explicitly assume any locational information about storage? Would mapping some portion of selected storage for 2019 IRP portfolios (for example, focused on specific areas with high commercial interest in storage as indicated by interconnection queues) be better than mapping none? If so, provide details of how this would be performed.

There are several storage resources that Community Choice Aggregators (CCAs) have contracted and are in the process of contracting. These resources are not part of the "baseline" storage resources (1,449MW) modeled in RESOLVE. At a minimum, the size and locations of CCA-contracted and planned storage resources should be considered for the resource-to-busbar mapping purposes. CalCCA believes that the remaining "new build" storage capacity selected under the 2019 IRP portfolios need to be mapped based upon two screens as follows.

The first screen is the ability to interconnect the storage resource with no additional or minimal transmission interconnection and network upgrade costs. In the majority of the cases, this would mean mapping storage at or near existing generating resources with adequate residual transmission interconnection capability. This is consistent with current contracting which is focused primarily on pairing storage with renewable projects. As proposed under the busbar mapping methodology proposal[4] for all resources, storage busbar allocation in a given area should abide by the estimated transmission capability in each zone and sub-zone, triggering only those upgrades which are determined to be cost-effective during the formation of the IRP portfolios.

The second screen should take into account the level of commercial interest reflected in the CAISO generation interconnection queue. Currently, there is more than 39GW of battery storage capacity in the generation interconnection queue spread all over the CAISO-controlled grid. Several project attributes of this queued generation should be used in determining the location and size for battery storage resource mapping. These attributes should include the current on-line date, point of interconnection, project milestones, such as interconnection agreement status.

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[3] *Ibid*. See p. 53. The CAISO plans to seek Board approval on the proposed revised Deliverability Assessment Methodology in November 2019. Ibid. See p. 53.

[4] CPUC Staff Proposal: Methodology for 2019 IRP Resource-to-Busbar Mapping, CPUC Energy Division, October 18, 2019, p. 11.

The ability of storage to reduce the reliance on existing gas-fired resources in the local areas and sub-areas needs to be a priority while mapping the storage resources. The CAISO conducted a comprehensive economic assessment of local capacity areas, also known as the *LCR Reduction Study*, as part of its 2018-2019 Transmission Plan.[5] It not only identified the potential transmission upgrades that would economically lower gas-fired generation capacity requirements in local capacity areas or sub-areas, but also explored and assessed alternatives, such as, conventional transmission and preferred resources including storage, to reduce or eliminate the need for gas-fired generation. The 2018-2019 TPP studied approximately half of the existing local areas and sub-areas, whereas as part of the 2019-2020 TPP, the CAISO plans to study the remaining half.[6] For example, in the 2018-2019 TPP, the LCR reduction study found one of the potential LCR reduction options for the overall *San Diego-Imperial Valley Area and San Diego* subarea was to install a 200 MW battery energy storage system in the western LA Basin.[7] Upon applying the above-mentioned two screens, 200MW of battery storage should be mapped at an appropriate busbar within the western LA Basin LCR area. Similar information for the remaining areas studied in the 2018-2019 TPP and 2019-2020 TPP[8] could be used to map storage resources.

Another important consideration to map storage resources is to site them, to the extent possible, at the same location as the existing or new renewable resources while ensuring that the total of the qualifying capacities of the renewable resource and battery does not exceed the capacity at the point of interconnection.[9] CalCCA notes that nearly 60% of storage capacity currently in the queue is hybrid, i.e., coupled with either solar or wind resources. Therefore, it is highly likely that such storage mapping would meet the second screen, i.e., commercial viability.

The resource mapping process described above and diagrammatically depicted in Figure 1 below would lead to a mix of standalone (or hybrid) storage resources in the local areas/sub-areas and hybrid storage mapped at the existing and new solar and wind projects, which we believe would also comply with the near- and long-term needs for cost-effectively obtaining additional resource adequacy capacity.

[5] Board-Approved CAISO 2018-2019 Transmission Plan, March 29, 2019.

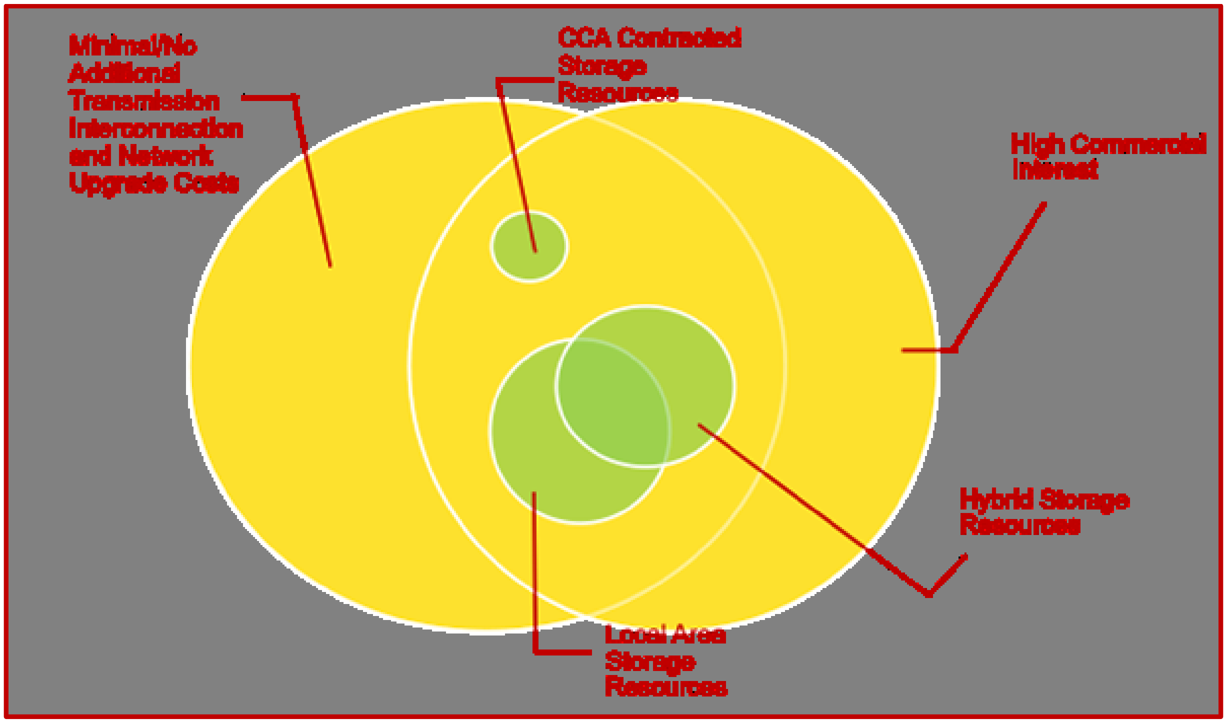
[6] "Economic Assessment of Local Capacity Areas Extension of 2018-2019 Transmission Plan," CAISO 2019-2020 TPP Stakeholder Meeting, September 25, 2019.

[7] http://www.caiso.com/Documents/Presentation-2018-2019TransmissionPlanningProcessMeeting-Nov16-2018.pdf, See Page 18 (page 199 of PDF) of the presentation, titled, "Reducing LCR Need Study for Eastern LA Basin and San Diego-Imperial Valley Areas," by David Le (CAISO) made at the 2018-2019 Transmission Planning Process Stakeholder Meeting, November 16, 2018.

[8] Preliminary findings of the LCR Reduction Studies are expected to be available by mid to end of November 2019. That would be in time for the current busbar to resource mapping exercise.

[9] For example, the CAISO allows the interconnecting projects to add energy storage to their interconnection request or operating Generating Facility. See "Opportunities for Adding Storage at Existing or New Generation Sites," CAISO Stakeholder Call, October 10, 2019.

Figure 1: Diagrammatic Representation of CalCCA's Storage to Busbar Mapping Approach



CalCCA appreciates the opportunity to provide comments at this stage and looks forward to participating in the future.

Sincerely,

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements.	R.16-02-007 (Filed on February 11, 2016)

COMMENTS OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION
ON PROPOSED DECISION REQUIRING
ELECTRIC SYSTEM RELIABILITY PROCUREMENT FOR 2021-2023

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October 2, 2019

TABLE OF CONTENTS

Contents

SUMMARY OF RECOMMENDATIONS

CalCCA supports the Proposed Decision's general direction, but recommends that the Commission modify the PD to:

- ✓ Direct Energy Division Staff to collaboratively undertake, in coordination with the California Independent System Operator and other stakeholders, a more rigorous analysis of system needs and solutions while the Commission pursues "least-regrets" actions;
- ✓ Bring internal consistency to the PD's conclusions that additional resources are needed, and consider whether resources under development today will meet that need and avoid unnecessary extensions of OTC retirement dates;
- ✓ Allocations resulting from the incremental procurement mandate should be adjusted to account for load migration resulting from the SB 237 Direct Access expansion in 2020; and
- ✓ Clarify that the compliance requirements arising from the Commission's directive will be tradable.

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements.	R.16-02-007 (Filed on February 11, 2016)

COMMENTS OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON PROPOSED DECISION REQUIRING ELECTRIC SYSTEM RELIABILITY PROCUREMENT FOR 2021-2023

Pursuant to Rule 14.3 of the Commission's Rules of Practice and Procedures, the California Community Choice Association[1] submits these opening comments on the proposed *Decision Requiring Electric System Reliability Procurement for 2021-2023* (Proposed Decision or PD).

I. INTRODUCTION

CalCCA supports the Commission's concern "to ensure safe and reliable service, in a manner that keeps the electricity sector on a path to the 2030 greenhouse gas (GHG) emissions goals"[2] set by the Legislature in Senate Bills (SB) 350 and 100 and D.18-02-018. Responding to this concern, the PD concludes that system RA supply beginning in 2021 is uncertain,[3] and

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1 California Community Choice Association represents the interests of 19 community choice electricity providers in California: Apple Valley Choice Energy, Clean Power SF, Clean Power Alliance, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Monterey Bay Community Power, Peninsula Clean Energy, Pioneer Community Energy, Pico Rivera Innovative Municipal Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Jacinto Power, San Jose Clean Energy, Silicon Valley Clean Energy, Solana Energy Alliance, Sonoma Clean Power, and Valley Clean Energy.

2 Proposed Decision at 1.

3 PD, Finding of Fact 3, at 47.

additional resources are needed to integrate increased volumes of renewable resources.[4] The Proposed Decision thus adopts a "least regrets" strategy, recommending extensions of once-through-cooling (OTC) plant retirements and directing incremental resource procurement.[5] Critically, the PD allows LSEs other than investor-owned utilities (IOUs) to participate in meeting the stated goals, implicitly recognizing that LSEs are best equipped to assess the risks and benefits of available resource options for serving their customers. In these respects, CalCCA appreciates the PD's consideration of community choice aggregators' interests and generally supports the PD's direction.

While CalCCA supports the strategy to defer retirement of certain OTC plants and to procure incremental system RA capacity, the PD warrants modification in certain respects. CalCCA recommends that the Commission modify the PD to:

- ✓ Direct Energy Division Staff (Staff) to collaboratively undertake, in coordination with the California Independent System Operator and other stakeholders, a more rigorous analysis of system needs and solutions while the Commission pursues "least-regrets" actions;
- ✓ Bring internal consistency to the PD's conclusions that additional resources are needed, and consider whether resources under development today will meet that need and avoid unnecessary extensions of OTC retirement dates;
- ✓ Allocations resulting from the incremental procurement mandate should be adjusted to account for load migration resulting from the SB 237 Direct Access expansion; and
- ✓ Clarify that the compliance requirements arising from the Commission's directive will be tradable.

Proposed Findings of Fact, Conclusions of Law and Ordering Paragraphs to modify the PD in these respects are provided in Appendix A.

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4 PD, Finding of Fact 3, at 47.
5 PD, Conclusion of Law 1 at 50.

II. THE COMMISSION'S RELIABILITY CONCERNS WARRANT A RIGOROUS AND TRANSPARENT ANALYSIS TO ENSURE THE RIGHT QUANTITY, TECHNOLOGY, AND TIMING OF INCREMENTAL RESOURCE DEPLOYMENT

CalCCA recognizes the inherent tensions between immediate action, as outlined in the PD, and taking time to gain greater certainty regarding the extent of future system RA needs. For this reason, CalCCA recommended in its opening comments on the June 20 Ruling[6] that the Commission pursue two parallel paths: analysis and action.[7] While the PD sets off on the path of least-regrets action, it overlooks the need for more rigorous analysis to more bring a higher level of certainty to the Energy Division's initial stack assessment. A parallel track approach, which simultaneously triggers immediate initial action by LSEs while initiating an accelerated statewide analysis of the reliability problem and solutions, would better serve the public interest.

A more rigorous analysis is crucial for resolving several uncertainties evidenced by the varying and shifting views of the reliability need across party comments. Examples of this uncertainty, identified in CalCCA's comments,[8] include the quantity and duration of OTC retirement deferral, the interplay between peak hour reliability concerns and post-peak hour concerns, the viability of certain technologies to reliably perform at their current net qualifying capacity (NQC) or effective load carrying capability (ELCC) ratings over their useful lives at higher penetrations or under future grid conditions, and the type and magnitude of resource expansion and retirement trends throughout the Western Electricity Coordinating Council. And

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6 *Assigned Commissioner and Administrative Law Judge's Ruling Initiating Procurement Track and Seeking Comment on Potential Reliability Issues,* issued on June 20, 2019 (June 20 Ruling).

7 *Opening Comments of California Community Choice Association on Assigned Commissioner and Administrative Law Judge Ruling Initiating Procurement Track and Seeking Comment on Potential Reliability Issues*, July 22, 2019 (CalCCA Opening Comments) at 2.

8 *See Reply Comments of California Community Choice Association on Assigned Commissioner and Administrative Law Judge Ruling Initiating Procurement Track and Seeking Comment on Potential Reliability Issues,* August 12, 2019 (CalCCA Reply Comments) at 9-17.

critically, the availability of import RA, which the Commission has begun to examine in R.17-09-020, is pivotal to the assessment of the problem and viable solutions.

This lack of clarity is highlighted in the varying results and unresolved questions outlined by party comments. While CalCCA was able to roughly validate Staff's supply-stack analysis,[9] the precise scope of the baseline resources underlying the analysis remains unresolved. Moreover, CalCCA raised specific concerns with the analyses presented by Southern California Edison Company (SCE)[10] and CAISO comments.[11] Since that time, uncertainty has only increased. In recent *ex parte* communications, the CAISO has urged the Commission to consider additional procurement to address both the timely retirement of OTC generation and the retirement of the Diablo Canyon Power Plant in 2024 and 2025.[12] The lack of a reasonably shared vision of how to assess the problem demonstrates the need for a more granular quantitative analysis.

This quantitative uncertainty greatly increases the risk of misdirected or excessive procurement, which will have significant consequences for CCA and bundled customers. As CalCCA observed, absent a robust analysis with greater granularity and greater clarity on input assumptions than the Staff's supply stack demonstrated, "investment may not be targeted toward its highest use and will drive up procurement costs in large increments."[13] CalCCA's members will invest considerable ratepayer funds in securing incremental capacity to respond to any

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[9] CalCCA Opening Comments at 3.

[10] *Southern California Edison Company's (U 338-E) Amended Opening Comments on Assigned Commissioner and Administrative Law Judge's Ruling Initiating Procurement Track and Seeking Comment on Potential Reliability Issues*, July 31, 2019 (SCE Amended Comments).

[11] *Comments of the California Independent System Operator Corporation*, July 22, 2019 (CAISO Opening Comments).

[12] *See generally Notice of Ex Parte Communication by the California Independent System Operator,* Sept. 25, 2019.

[13] CalCCA Opening Comments at 10.

procurement mandate and are concerned about the implications for future resource strategies. The uncertainty thus calls for utilization of a short-, mid- and long-term planning horizon in the context of developing new long-lived resources. Further, greater analysis will facilitate the exploration of which strategies best incorporate preferred resources and meet other shared policy goals.

The exigent circumstances deserve more clarity and transparency than the process thus far has afforded. CalCCA offered clear recommendations for additional process in its comments on the June 20, 2019, ruling.[14] The Commission should also work with the CAISO to reexamine the metrics used to evaluate system requirements. The CAISO has called into question the way in which RA system requirements are set today, observing a "strong potential for insufficient resources in the hours immediately after the gross peak hour…."[15] The analysis should thus identify how to establish a reasonable measure of system peak. CalCCA also reiterates its request that the Commission begin development of a more coherent process to identify system RA needs and to make sure LSEs meet those needs.[16]

The Commission has a tremendous opportunity to improve policy and accelerate achievement of statewide climate goals if the near-term needs are met with careful thought and analysis. CalCCA appreciates the PD's intent to act swiftly in the procurement of incremental capacity and generally supports an approach which includes some immediate action by LSEs to secure incremental capacity. The Commission, however, should modify the PD to integrate further analysis into the process to ensure the right resources are procured to address the reliability need while also optimizing for environmental, ratepayer, and other policy goals.

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14 CalCCA Reply Comments at 13-15.
15 CAISO Opening Comments at 1.
16 *Id.* at 22.

III. THE COMMISSION SHOULD REVIEW THE PD'S CALCULATION OF NEEDED RESOURCES TO PREVENT UNNECESSARY EXTENSIONS OF OTC RETIREMENT DATES

The PD's conclusions regarding the amount and timing of additional resource needs are confusing, at best. The Commission should review the PD's conclusions to ensure its decision does not unnecessarily trigger OTC plant retirement extensions, providing clarity about the megawatts of need it is attempting to address and the associated timing. CalCCA supports the expedient retirement of OTC plants as a critical action necessary to avoid increased greenhouse gas emissions, reduce local criteria pollution, and minimize environmental impacts to sensitive marine ecosystems. Recognizing the exigent nature of the reliability concerns expressed in the PD, CalCCA strongly encourages the Commission to limit any OTC retirement extensions to those absolutely necessary for the continued reliability of the state's electrical system. Further, CalCCA encourages the Commission to ensure the contractual and operational extension of any OTC facilities is conducted in a manner which minimizes facility runtime and corresponding environmental impact and ensures the facility is ultimately retired once the need for it is displaced by incremental resources.

The Commission should direct staff to reevaluate how the new resources identified in the September 2019 LSE data responses would reduce the need for OTC extensions. CalCCA contends that extension of Ormond Beach Generating Station (Ormond) and Redondo Beach Generating Station (Redondo) retirement dates is unnecessary and, as the PD notes, the Redondo extension may have logistical hurdles.[17] While CalCCA supports some degree of OTC extension as an unfortunate but prudent reliability insurance policy, any recommended extensions should

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[17] PD at 18.

be carefully tailored and designed to minimize OTC extensions and operation and, ultimately, ensure the ultimate timely retirement of any extended facility.

The PD's approach requires modification to remove duplication that results from having OTC extensions run in parallel with incremental procurement. The PD concludes that "the original June 20, 2019 Ruling suggestion of 2,500 MW of system resource adequacy capacity is still appropriate based on the identified need and to balance against both the potential for some OTC retirement date extensions not to be granted by the Water Board and also against the potential tightening of the import market….."[18] These parallel strategies, however, would create anywhere from 2,500 MW to 5,720 MW of incremental resources depending on the year, as discussed below. Adding further confusion, the PD also appears to conclude that 6,250 MW of capacity in addition to the baseline resources for 2022 in the Preferred System Plan (Baseline Resources) will be necessary by summer 2021:

> In addition to extension of 2,500 to 3,750 MW of OTC capacity, another 2,500 MW of incremental system resource adequacy and renewable integration resources will be needed by summer 2021, as a "least regrets" amount necessary to ensure system reliability.[19]

The PD gives the mandate yet another spin in its Ordering Paragraphs, recommending that:

> the State Water Resources Control Board (SWRCB) "extend the once-thru-cooling compliance deadlines for up to three years of at least 2,500 megawatts (MW and up to 3,750 MW of capacity, of units with current compliance deadlines of December 31, *2020 in order to allow time for new clean electricity capacity to come online*.[20]

This passage suggests, quite logically, that the purpose of the OTC extensions is to allow for the mandated 2,500 MW of incremental resources to come on line; the PD staggers online dates for these new resources beginning with 60 percent in 2021, 80 percent in

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[18] PD at 30.
[19] PD, Finding of Fact 16 at 49.
[20] PD, Ordering Paragraph 1 at 55.

2022 and 100 percent by August 1, 2023.[21] Accepting this intent, and assuming that all 3,750 of OTC plants remain on line pending bringing the new capacity online, would result in the following levels of additional system RA megawatts:

	2021	***2022***	***2023***
Once-through-Cooling	3,750	3,750	0
Incremental Capacity	1,500	2,000	2,500
Total Capacity	5,250	5,750	2,500

CalCCA suggests that if the goal, as the PD suggests, to use OTC as a stop-gap while incremental resources are added, both incremental resources and OTC capacity are not needed in 2021.

Making matters more challenging, nowhere does the PD identify how much capacity beyond the adopted baseline is actually needed in 2022 and 2023, nor does it discuss other changes in the supply balance that will change during that period or the methodology it used to determine the mandate.

Under these circumstances, and assuming development of incremental resources consistent with the proposed incremental resource mandate, it is unnecessary to extend the retirement of or recontract Ormond and Redondo. Further, the PD acknowledges that recontracting the Redondo plant may not even be feasible: "the owner of Redondo Beach is in the process of selling the property in anticipation of the OTC compliance deadline, and therefore this plant may not be a candidate for an OTC compliance deadline extension." [22]

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21 *Id.*, Ordering Paragraph 2 at 55 (emphasis supplied).

22 PD at 18.

To further limit reliance on OTC plants, the Commission should also develop a method for adjusting the requirements as new resources come online. For example, even inclusion of the incremental resources reported in the September 16, 2019, LSE data responses is likely to reduce the overall need by several hundred MW, which changes the need for particular OTC facilities. Currently, a 2,500 MW minimum need cannot be met without Ormond, but if that need is lowered to 2,200 MW through incremental procurement, Ormond would not be needed. Again, this highlights the critical nature of a more accurate quantitative estimate of the need.

Similarly, to limit the amounts of OTC plants kept on line and to assist LSEs in meeting their procurement obligations, the Commission should clearly indicate that storage and storage hybrid resources can be included as new resources. The CAISO is currently working on rules for how much RA are provided by hybrid resources to help address 2021 reliability needs. The Commission should recognize this process and agree to accept the outcome for counting these resources for RA compliance. The CAISO has also indicated that the quickest way to get new resources through their interconnection processes is to use their "Material Modification Assessment Process," which allows for changes to the configuration at existing resources. Consequently, adding storage to an existing resource, especially a solar or wind resource, can be quickly accommodated through this process. The CAISO has suggested that such resources could provide a significant amount of capacity and would likely be especially helpful in meeting the needs they see in the hours after the afternoon peak. Including these resources as eligible new resources will provide direction and greatly increase the universe of possible resources, which should help keep costs down.

For these reasons, CalCCA strongly encourages the Commission to expeditiously undertake a more refined analysis in the next three months, accounting for all new resources on the horizon, to gain greater clarity on the true needs. The Commission should not haphazardly drive OTC extensions or expensive procurement by LSEs – potentially the wrong type or at the wrong time – without more consideration.

Pending conclusion of this assessment, however, the Commission should take action. It should recommend to the SWRCB the extension of the retirement dates for Alamitos and Huntington Beach, which together could provide 1,400 MW of system RA capacity.[23] Further, the Commission should incorporate processes to limit the use of any extended OTC facility to address only actual peak energy shortfalls and establish a process for the OTC facility to retire once it has been displaced by incremental resources. Specifically, the PD should incorporate CalCCA's recommendations[24] or develop alternative contract structures which limit facility operations and consequent environmental impacts to the most pressing reliability hours.

IV. ALLOCATIONS RESULTING FROM THE INCREMENTAL PROCUREMENT MANDATE SHOULD BE ADJUSTED TO ACCOUNT FOR LOAD MIGRATION RESULTING FROM THE SB 237 DIRECT ACCESS EXPANSION

A 4,000 gigawatt hour increase in Direct Access (DA) enrollment will occur in 2020, pursuant to Senate Bill 237[25] and Decision 19-05-043.[26] CalCCA requests that any incremental procurement mandate allocations to LSEs resulting from the final decision be provisional, subject to adjustment for new DA load migration. While load migration, in general, should be considered in implementing the procurement allocations, the Commission should make clear in the final decision that this known, significant load migration will be accounted for in determining the final allocation to each LSE.

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23 The PD identifies the Alamitos Generating Station (Alamitos) as presenting an additional 1,200 MW and the Huntington Beach Generating Station (Huntington) an additional 200 MW. PD at 16.

24 CalCCA Opening Comments at 19-20.

25 1 Stats. 2018, Ch. 600, amending Public Utilities (Pub. Uitl) Code section 365.1

26 D.19-05-043 at 1.

V. THE COMMISSION SHOULD CLARIFY THAT INCREMENTAL PROCUREMENT ALLOCATIONS WILL BE TRADABLE

As it directs incremental system RA procurement, the Commission should maximize program flexibility to minimize the burden of LSE compliance and reduce costs for LSEs and their customers. To add flexibility, CalCCA requests that the Commission make clear that procurement requirements resulting from the mandate will be tradable. Making the requirement "tradable" addresses at least two potential scenarios.

Tradability will allow an LSE to address challenges created by the arbitrary 10-year contract requirement, which may make such transactions infeasible to the detriment of an efficient statewide solution. For instance, an LSE that has new resources coming online in 2023 for its own compliance obligation may only need two years' worth of capacity from another LSE which may be long on its own obligation. The impact on the LSE is reduced by allowing for inter-LSE transactions under ten years for projects which have underlying ten year contracts with the initial LSE counterparty.

Making allocations tradable will also provide another tool for LSEs to balance their positions. For example, assume LSE A has a mandated incremental resource requirement of 100 MW but chooses to build a 200 MW generation plant, which it wishes to retain in its portfolio. Assume that LSE B also has a mandated requirement of 100 MW, but already has a fully resourced portfolio and does not want to add new capacity its portfolio. If the requirements are tradable, LSE B could procure the "incremental" attribute associated with 100 MW of LSE A's plant to satisfy its mandated requirement without investing in a new or incremental resource. Trading the requirement in this way would allow LSEs to balance their portfolios, while collectively still meeting the mandated procurement requirement.

To ensure that sufficient resources are in place by the identified compliance dates, a deadline for notifying the Commission of trades for a particular year should be set one year in advance. If, for example, compliance is due on August 1, 2021, all trades of positions for that period must be provided to the Commission by August 1, 2020.

VI. THE COMMISSION SHOULD LIMIT THE USE OF THE CAM IN MEETING 2021 REQUIREMENTS.

While the PD alludes to the potential for additional CAM procurement by SCE,[27] it is unclear when or under what conditions this would occur. CalCCA submits that the CAM should not be used under any circumstances for resources procured as a result of the mandated procurement. If such resources ultimately exceed the IOUs bundled load, either at the outset of a program or as a result of load migration, above-market costs should be recovered through the Power Charge Indifference Adjustment (PCIA).

The CAM mechanism should only be applied to address shortfalls that might exist after LSEs have been given a full opportunity to self-procure incremental resources. Any allocation of the CAM resources/costs should take into consideration each LSEs' contribution to reducing the overall system need, so that parties that do not perform are permitted to "lean" on parties that have met their obligation. This may require modifications to the CAM mechanism or the need to develop a different form of billing to LSEs, although this task is not immediately urgent provided the commitment for fair allocation based on each LSE's procurement is expressed in the final decision as the objective.

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[27] PD at 33.

VII. CONCLUSION

For all of the foregoing reasons, CalCCA recommends the adoption of the recommended modifications to the Proposed Decision set forth herein.

Respectfully submitted,

Evelyn Kahl
Counsel to
California Community Choice Association

October 2, 2019

APPENDIX A

Revised Findings of Fact, Conclusions of Law and Ordering Paragraphs

Findings of Fact:

16. The capacity of OTC plans subject to retirement by the end of 2020 is needed to maintain system reliability beginning in 2021 until ~~In addition to extension of 2,500 to 3,750 MW of OTC capacity, another~~ 2,500 MW of incremental system resource adequacy ~~and renewable integration resources~~ will be needed ~~by Summer 2021,~~ as a "least regrets" amount necessary to ensure system reliability.

NEW: Minimizing OTC retirement extensions is a critical action to avoid increased greenhouse gas emissions and more quickly achieve the state's climate goals.

Ordering Paragraphs:

1. The Commission recommends that the State Water Resources Control Board extend the once-thru-cooling compliance deadlines the Alamitos and Huntington Beach plants for up to three years of at least 1,400 ~~2,500~~ megawatts (MW) ~~and up to 3,750 MW of capacity, of units with current compliance deadlines of December 31, 2020,~~ in order to allow time for new clean electricity capacity to come online.

NEW: The Energy Division should undertake a more rigorous study of system RA needs for 2021-2023 within 14 days following the effective date of this decision.

NEW: Any incremental procurement mandate allocations to LSEs resulting from this decision will be provisional, subject to adjustment for new Direct Access load migration pursuant to SB 237.

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

Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements.	R.16-02-007

CALIFORNIA COMMUNITY CHOICE ASSOCIATION COMMENTS ON REVISED PROPOSED DECISION REQUIRING ELECTRIC SYSTEM RELIABILITY PROCUREMENT FOR 2021-2023

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October 31, 2019

TABLE OF CONTENTS

TABLE OF AUTHORITIES

Page(s)

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements.	R.16-02-007

CALIFORNIA COMMUNITY CHOICE ASSOCIATION
COMMENTS ON REVISED PROPOSED DECISION REQUIRING ELECTRIC SYSTEM RELIABILITY PROCUREMENT FOR 2021-2023

The California Community Choice Association (CalCCA) submits these Comments on the *Revised Proposed Decision Requiring Electric System Reliability Procurement for 2021-2023* (Alternate Decision),[1] issued on October 21, 2019, pursuant to Rules 14.5 and 14.6 of the Commission's Rules of Practice and Procedure.

I. INTRODUCTION

The Alternate Decision significantly modifies the Proposed Decision in numerous ways. Most significantly, the Alternate Decision:

(1) Increases the requirement for incremental resource adequacy (RA) procurement from 2,500 MW to 4,000 MW by 2023;

(2) Modifies the baseline used to distinguish incremental from existing resources, including a significant modification of the treatment of import RA;

(3) Broadens the scope of allocation of procurement responsibility from the Southern California Edison Company (SCE) transmission access charge (TAC) area to the TAC areas of all three investor-owned utilities (IOUs);

(4) Modifies the methodology for allocating responsibility to individual load-serving entities (LSEs) within these TAC areas; and

(5) Modifies the Proposed Decision's recommendations for requesting extensions of the retirement dates for once-through-cooling (OTC) units.

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1 CalCCA asserts that the "Revised Proposed Decision," which materially revises the Proposed Decision, meets the definition of the "alternate" under Public Utilities Code §311(e) and "alternate proposed decision" under Rule 14.1(d).

In addition, the Alternate Decision clarifies and refines other details for implementation of the incremental RA procurement requirement.

While CalCCA continues to support the direction of the Commission's "least regrets" policy, the Alternate Decision errs in some areas. Most notably, it adopts a 4,000 MW directive without any study in the record to support this value and with apparent errors in the calculation of load shares for individual LSEs. As a result, it unnecessarily imposes an unreasonable pace of development and risks unnecessarily increasing customer costs. CalCCA continues to highlight the importance of taking the time necessary to actually study and understand system conditions.

CalCCA thus offers the following recommended changes to the Alternate Decision:

1. Adopt an initial target of 3,300 MW of incremental procurement for 2023, consistent with the Proposed Decision, as adjusted to reflect removal of the Sutter Power Plant (Sutter) and Inland Empire Energy Center (Inland) from the 2022 baseline used in the Staff's stack analysis (Baseline).

2. Conduct an expeditious, rigorous analysis of the actual 2023 system RA requirement in coordination with the California Independent System Operator (CAISO) and other stakeholders and adjust the initial target based on the results of that analysis.

3. Phase in the incremental RA requirement consistent with Southern California Edison Company's (SCE's) proposal of 20 percent for 2021, 60 percent for 2022 and 100 percent for 2023; the resulting 666 MW of incremental system RA capacity in 2021, combined with OTC extensions, will securely meet the forecasted 2021 shortfall with a margin of 41 percent.

4. Provide that import RA procurement will be eligible for compliance with the incremental RA procurement requirement to the extent an LSE exceeds its share of the minimum import RA assumed in the Baseline and the total import RA procured on a multi-year forward basis meets or exceeds the minimum.

5. Enable LSEs to "trade" compliance rights to optimize procurement and minimize costs to ratepayers.

6. Clarify that any individual procurement by a Community Choice Aggregator (CCA) or Electric Service Provider (ESP) of battery storage resources will be eligible as incremental RA procurement, recognizing the IOUs have already procured the existing battery storage requirement of 1,325 MW.

7. Update LSE allocations immediately following the launch of new Direct Access service under Senate Bill (SB) 237,[2] recognizing the likelihood of a 4,000 GWh load migration from either the IOUs or CCAs to ESPs and potential migration from IOUs to CCAs.

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[2] Stats. 2018, ch. 600, amending Public Utilities Code Section 365.1.

8. Clarify that the effective load carrying capability (ELCC) for renewable resources and energy storage will be fixed, solely for purposes of this incremental procurement requirement, at the time an irrevocable commitment is made by an LSE to procure the resource.

9. Refine the reference period for determination of compliance to prevent gaming that could impair reliability in months other than September.

Proposed Findings, Conclusions, and Ordering Paragraphs are provided as Exhibit A.

II. THE COMMISSION SHOULD MORE RIGOROUSLY ASSESS FUTURE SYSTEM RA REQUIREMENTS AND, IN THE INTERIM, MODERATE THE PROCUREMENT MANDATE

CalCCA supports the Commission's intent to take immediate action to address the identified reliability need, and the CCA community stands ready to pursue the development of new resources intended to maintain stability in California's electricity market. CalCCA is deeply concerned, however, with the significant increase in magnitude of the procurement order proposed in the Alternate Decision – an increase that is not attributed to any specific analysis and is not clearly justified by the record. Exacerbating this shortcoming, the Alternate Decision maintains the Proposed Decision's rapid phase-in of the requirement despite the Commission's intent to seek the extension of retirement dates for certain OTC generating plants. The Alternate Decision's conclusions are unsupported by the record, are internally inconsistent, and risk unnecessary costs for ratepayers of all LSEs.

The Proposed Decision directed "incremental procurement, beyond the baseline resources assumed for the Year 22 and included in the Preferred System Plan adopted in D.19-04-040, of system resource adequacy capacity of 2,500 MW…."[3] The Alternate Decision increases this amount to 4,000 MW.[4] Both of these requirements phase in at the same pace: "at least 60 percent by August 1, 2021, 80 percent by August 1, 2022, and 100 percent by August 1, 2023."[5]

The Alternate Decision starts from a reasonable premise, which CalCCA continues to support:

> [T]he original June 20, 2019 Ruling suggestion of 2,500 MW of system resource adequacy capacity is still appropriate based on the identified need and to balance against both the potential for some OTC retirement date extensions not to be granted by the Water

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3 Proposed Decision at 2.
4 Alternate Decision at 3.
5 Alternate Decision at 3; Proposed Decision at 2-3.

> Board and also against the potential for the tightening of the import market for California.[6]

In other words, the Commission concludes that 2,500 MW of resources above the 2022 baseline will be needed to secure reliability for 2021. Despite this clear statement of need, the Alternate Decision imposes "net" requirements of 5,265 MW in 2021, 4,574 MW in 2022 and 4,560 MW in 2023, as shown in the table attached as Exhibit B.

The Alternate Decision attempts to bridge the gap between its conclusions and the Proposed Decision. It states:

> We believe that the original June 20, 2019 Ruling suggestion of 2,500 MW of system resource adequacy capacity is still appropriate based on the identified need and to balance against both the potential for some OTC retirement date extensions not to be granted by the Water Board and also against the potential for the tightening of the import market for California.[7]

The Alternate Decision also explains:

> [B]ecause the proposed decision originally sought OTC compliance deadline extensions for a larger amount of capacity, and this amount has now been reduced considerably and scaled down over time, we see a need for additional procurement at the system level.[8]

Finally, it defends the unsubstantiated conclusion by observing that "procurement of resources is not an exact science."[9]

In essence, the Alternate Decision adopts "fudge factors" of 111 percent for 2021, 83 percent for 2022 and 27 percent for 2023. While CalCCA agrees that determining resource adequacy requirements "is not an exact science," the Alternate Decision goes too far and fails to recognize that its mandated procurement will come at a high cost to ratepayers. The requirement risks ratepayers paying for more MW of capacity than is actually needed to meet system RA requirements. Similarly, the exigency attached to the requirement will create a "seller's market" for a limited pool of available resources – impliedly, battery resources ready for expedited

6 Alternate Decision at 33.
7 Alternate Decision at 33.
8 Alternate Decision at 33.
9 *Id.*

deployment -- and thus increase the price paid by ratepayers for each MW procured on their behalf. CalCCA proposes three modifications to mitigate unnecessary ratepayer impacts.

First, the Commission should direct the development of a more rigorous and reliable system RA assessment in coordination with the CAISO and other stakeholders through a public process. CalCCA has outlined this proposal in detail four times in prior comments, and will not repeat the proposal here.[10] CalCCA emphasizes, however, that addressing procurement urgently and without clear analysis is unacceptable in the long run, as it places customers at risk for degradation in reliability, on the one hand, and unnecessarily higher costs on the other.

In conducting this assessment, the Commission should coordinate with the CAISO to differentiate between needs driven by load in the IOU TAC areas and needs driven more broadly by CAISO-wide load. Customers within the IOU TAC areas should not bear cost responsibility for providing reliability for load served by publicly owned utilities.

Second, pending this further analysis, the Commission should adopt an initial 2023 incremental system RA requirement of 3,300. This value represents the 2,500 MW requirement proposed in the Proposed Decision, adjusted to reflect the Alternate Decision's removal from the Baseline of approximately 831 MW of Sutter and Inland capacity. Once a more rigorous assessment has been completed, the requirement could be adjusted, if necessary, to reflect a more solid view of need in 2022-2024.

Third, the Commission should adopt SCE's proposed phase-in of the requirements. In its opening comments on the Proposed Decision, SCE proposes to realign the procurement timeline for incremental resources, specifically, to require LSEs to bring 20 percent, 60 percent, and 100 percent of incremental resources online by 2021, 2022, and 2023, respectively.[11] As SCE points out,

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10 *See Opening Comments of California Community Choice Association on Assigned Commissioner and Administrative Law Judge Ruling Initiating Procurement Track and Seeking Comment on Potential Reliability Issues* at 13-15 (CalCCA Reply Comments); *Reply Comments of California Community Choice Association on Assigned Commissioner and Administrative Law Judge Ruling Initiating Procurement Track and Seeking Comment on Potential Reliability Issues* at 3-18 (CalCCA Opening Comments); *Comments of California Community Choice Association on Proposed Decision Requiring Electric System Reliability Procurement for 2021-2023* (CalCCA PD Comments) at 3-6; *Amended Reply Comments of California Community Choice Association on Proposed Decision Requiring Electric System Reliability Procurement for 2021-2023* (CalCCA PD Reply Comments) at 2-3.

11 *Opening Comments of Southern California Edison Company (U 338-E) on Proposed Decision Requiring Electric System Reliability Procurement for 2021-2023* (SCE Opening Comments) at 11-12.

the Proposed Decision's "compressed timeframe to procure resources and bring 60 percent online as early as August 1, 2021 is not practical."[12]

CalCCA agrees with SCE and observes that the aggressive pace of both the Alternate Decision and Proposed Decision is unsupported and would lead to a substantial margin above forecasted need:

- As shown in Exhibit B, the Alternate Decision leaves a "fudge factor" of 111 percent for 2021, 83 percent for 2022 and 82 percent for 2023.
- As shown in Exhibit C, SCE's approach, when combined with the Commission's target of 4,000 MW, would yield a still-generous margin above the forecasted need of 47 percent for 2021, 51 percent for 2022, and 82 percent for 2023.
- As shown in Exhibit D, pending the full assessment of need, adopting a requirement of 3,331 MW, allocated as SCE proposes, yields a more reasonable margin of 41 percent for 2021.

In light of these outcomes, CalCCA recommends a 3,331 MW requirement for 2023, phased in as proposed by SCE, to ensure reliability while avoiding unnecessary and excessive ratepayer costs.

III. THE COMMISSION SHOULD CLARIFY AN LSE'S ABILITY TO RELY ON IMPORT RA TO MEET THE PROCUREMENT REQUIREMENT

The Alternate Decision creates substantial ambiguity around the treatment of import RA in the Baseline and, in turn, the counting of import RA for purposes of compliance with the new procurement requirement. The initial Staff "stack analysis" [13] assumed that 8,800 MW of import RA would be required to meet 2021 requirements.[14] Using that assumption, the June 20 Ruling concluded that 2,000 MW of incremental capacity would be required to meet 2021 requirements. The Alternate Decision unfortunately provides no information regarding the import RA assumption underlying the 4,000 MW incremental procurement requirement, leaving it unclear

[12] *Id.* at 11-12; *see* CalCCA PD Reply Comments at 4.

[13] CalCCA continues to note that the stack analysis upon which the original requirement was based is not in the record, calling into question the Alternate Decision's conclusions under *The Utility Reform Network v. Public Utilities Com.* (*Oakley*), (2014) 223 Cal. App. 4th 945. *See* CalCCA PD Reply Comments at 2-3.

[14] *Assigned Commissioner and Administrative Law Judge's Ruling Initiating Procurement Track and Seeking Comment on Potential Reliability Issues* (June 20 Ruling) at 12.

whether it is or is not based on the 8,800 MW value originally used in the Staff's stack analysis.[15]

CalCCA recommends, as a preliminary step, that the Commission clearly define its assumptions about import availability in whatever baseline underlies its final requirement. In the Commission's fuller assessment, CalCCA supports CAISO's proposal to set the baseline, for purposes of incremental accounting, at 5,340 MW, the average historical contracted imports from 2015 through 2018.[16] In addition, the Commission should consider a multi-year showing for system RA, as proposed in R.17-09-020, to get a more forward look at contracted import RA. With this step, the Commission could count import RA as incremental under two conditions: (1) the LSE has procured its load share of the baseline import RA requirement and (2) collectively, all LSEs have procured sufficient import RA to meet the baseline. The Commission should develop a clear import accounting methodology for purposes of the incremental procurement requirement in implementation workshops.

IV. THE COMMISSION SHOULD ALLOW TRADING OF QUALIFYING CAPACITY AMONG LSES

CalCCA continues to recommend that LSEs be permitted to "trade" qualifying procurement to maximize program flexibility and thus reduce costs for ratepayers.[17] In other words, if one LSE develops an eligible resource, it could dedicate any portion of the resource or any period of the resource commitment to meet the compliance requirement of another LSE. The "compliance right" could be sold as an attribute separate from the system RA capacity, itself. This can ensure that sufficient resources will be online to meet the system reliability needs while minimizing costs to ratepayers.

Tradability will allow an LSE to address challenges created by the 10-year contract requirement, which may make such transactions infeasible to the detriment of an efficient statewide solution. For instance, an LSE that has a new resource coming online in 2023 for its own compliance obligation may only need a two-year bridge to its online date; another LSE may have procured resources in excess of its allocated share for 2021-2022. Rather than requiring

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15 Alternate Decision at 27-28.

16 CAISO Oct 2, 2019 Comments at p. 8-9; http://www.caiso.com/Documents/Oct2-2019-Comments-ReliabilityProcurementProposedDecision-IRP-R16-02-007.pdf

17 *See* CalCCA PD Comments at 11.

backstop procurement for the LSE that is short for 2021-2022, the LSE with a long position could transact the 2021-2022 share of incremental procurement compliance to the short LSE. This reduces excess procurement and will reduce the overall cost of compliance for both LSEs' ratepayers.

Similarly, making allocations tradable will provide a tool to address "lumpy" procurement. One LSE, for example, may invest in a utility-scale project for 2022 that exceeds the share of the incremental procurement allocated to the LSE and its customers. It should be permitted to dedicate any additional "compliance" rights to another LSE that chooses not to invest in a new resource, regardless of whether the RA capacity is actually sold to the other LSE.

The urgency of the Commission's incremental procurement mandate risks substantial rate impacts for customers of all LSEs. The risk compels the Commission to pull out all of the stops to mitigate excess procurement. The Commission should encourage LSEs to work together to meet the incremental requirement. Enabling trading of compliance rights will move the framework in the right direction.

V. THE COMMISSION SHOULD CLARIFY THE DEFINITION OF "INCREMENTAL" ENERGY STORAGE RESOURCES

The Alternate Decision clarifies that the Baseline includes "approximately 1,325 MW of storage that is slated to come online by 2024 due to storage development activities already underway."[18] As the Alternate Decision explains, these resources are "represented generically and not specifically."[19] It further specifies that parties' incremental procurement must be adjusted to "detail specific storage resources with projected online dates prior to the end of 2022."[20] Beyond this statement, the Alternate Decision leaves the rules for counting new storage projects ambiguous.

Ambiguity arises from the fact that the 1,325 MW of Baseline storage appears to have been already secured. Decision 13-10-040 established a 2024 energy storage procurement goal of 1 percent of 2020 peak load for CCA programs.[21] Decision 17-04-054 clarified that the CCA's obligation would be reduced to the extent of its proportional share of IOU storage procurement

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18 Alternate Decision at 30.

19 *Id.*

20 Alternate Decision, Ordering Paragraph 6 at 73.

21 D.13-10-040 at 36, 77 (Ordering Paragraph 5).

paid for by the CCA's customers through a non-bypassable charge.[22] An August 1, 2019, advice letter filed jointly by the three IOUs reveals that they have contracted for 100 percent of the mandated energy storage goals, including 100 percent of CCAs' share of that procurement.[23]

In light of the IOUs' full procurement of Baseline energy storage requirements, the Commission should clarify that all additional individual LSE storage projects should be counted as incremental and further clarify how energy storage resources will be counted toward compliance.[24] This is exceptionally important because many or most of the new resources capable of being online by August 1, 2021 will be storage resources.

VI. THE COMMISSION SHOULD UPDATE LSE ALLOCATIONS OF THE PROCUREMENT REQUIREMENT TO REFLECT LOAD MIGRATION RESULTING FROM THE EXPANSION OF DIRECT ACCESS OR OTHER MAJOR LOAD MIGRATIONS

The Alternate Decision, like the Proposed Decision, does not account for the expansion of Direct Access under SB 237. Decision 19-05-043 provides, consistent with the statute, that a 4,000 gigawatt hour (GWh) increase in Direct Access (DA) enrollment will be implemented in 2021.[25] As a result, load migration in this amount is likely to occur, which could significantly shift the load share of one or more individual LSEs. CalCCA therefore requests that any incremental procurement mandate allocations to LSEs resulting from the final decision be provisional, subject to adjustment for new DA load migration.[26] The adjustment for load migration should be made concurrent with the update to the overall procurement requirement following the completion of the system RA assessment discussed in Section II.

It is also likely that load will migrate from IOUs to CCAs in 2021. The incremental system RA requirement allocations should also be adjusted to reflect any such load migration consistent with any implementation plan filed by a CCA to serve load in 2021.

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22 D.17-04-039 at 68 (Ordering Paragraph 6).

23 *See Advoce 4048-E (Southern California Edison Company U 338-E); Advice 5605-E (Pacific Gas and Electric Company U 39-E); Advice 3408-E (San Diego Gas & Electric Company U 902-E)* (August 1, 2019), Table 6.

24 For example, will the storage Net Qualifying Capacities (NQCs) be linear, such that a 2 hour 40MW battery give an LSE 20 MW of NQC?

25 D.19-05-042 at 13.

26 CalCCA also requested this modification in its comments on the PD. *See* CalCCA PD Comments at 10.

VII. THE COMMISSION SHOULD CLARIFY COUNTING RULES FOR RENEWABLE AND ENERGY STORAGE RESOURCES

The determination of ELCC values for certain renewable resources and energy storage is shifting, and the CAISO has signaled the need to reexamine these values in light of the shifting peak requirements. Consequently, the Commission should clarify which ELCC calculations will be used to determine compliance with the incremental system RA procurement requirements. To provide certainty, CalCCA requests clarification that the calculation methodology in place at the time an LSE makes an irrevocable commitment to a resource will be used to determine the resource's compliance value for purposes of the incremental system RA procurement. Any other approach would fail to give LSEs adequate notice to meet the new requirements and lead to inefficient procurement and an unreasonable increase in procurement costs.

VIII. THE COMMISSION SHOULD CLARIFY THAT THE ADOPTED METHODOLOGY FOR ALLOCATION AMONG LSES

CalCCA requests two modifications of the Commission's rules for allocation of the incremental procurement requirement. First, the Commission should clarify that, in the future, all *system* RA requirements will be allocated to LSEs in all IOU TAC areas. The broader allocation in this proceeding should set precedent for allocation of system RA obligations arising from the replacement of Diablo Canyon Power Plant or other system resources in the future. Second, the Commission should clarify that the two-step methodology for allocation of the requirements among LSEs will not set precedent for future allocations. This methodology sacrifices accuracy for confidentiality, and the Commission should consider further in the future how to balance these interests.

IX. THE COMMISSION SHOULD CLARIFY THE REFERENCE PERIOD FOR COMPLIANCE COUNTING

The Alternate Decision clarifies that September NQC values will be used to determine the compliance value of incremental resources LSEs procure.[27] For new resources, requiring September NQC values will ensure that the resources are available in other months. However, there could be circumstances where providing September NQC values would not provide that

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[27] Alternate Decision at 59.

assurance. For example, if an entity procured only September NQC from a mothballed facility or import, there would not necessarily be assured availability in other months unless the procuring LSE actually used the resource for annual RA compliance. The Commission should consider mechanisms to prevent gaming of the requirement in implementation workshops.

X. CONCLUSION

For all of the foregoing reasons, CalCCA respectfully requests the adoption of the proposed modifications of the Alternate Decision as specified in these comments and Exhibit A.

October 31, 2019

Respectfully submitted,

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EXHIBIT A

PROPOSED FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDERING PARAGRAPHS

Findings of Fact:

16. In addition to extension of OTC capacity, another minimum of ~~4,000~~ 3,331 MW of incremental system resource adequacy and renewable integration resources will be needed by Summer 2021, as a "least regrets" amount necessary to ensure system reliability.

18. The most logical baseline against which to measure incremental resources is the set of baseline resources used to develop the PSP adopted in D.19-04-040, with certain adjustments, reduced by 831 MW to reflect the mothballing of the Sutter and Inland Empire plants. The baseline resources should be those included for the year 2022, the year that most closely matches the timeframe associated with this decision.

Conclusions of Law:

9. It is reasonable for the Commission to require ~~4,000~~ 3,331 MW of incremental system resource adequacy resources to be procured, with at least ~~60~~ 20 percent online by August 1, 2021, ~~80~~ 60 percent by August 1, 2022, and 100 percent by August 1, 2023.

21. The Commission should prefer all-source procurement of resources, including demand-side resources and preferred resources, to the extent possible, as long as resources can be shown to be incremental to the 2022 baseline set of resources. New, greenfield fossil-fueled resources and OTC units are not eligible to meet the ~~4,000~~ 3,331 MW incremental need identified in this decision.

26. The Commission should require that the incremental system resource adequacy and renewable integration resources required to be procured by this decision come online at least ~~60~~ 20 percent by August 1, 2021, ~~80~~ 60 percent by August 1, 2022, and 100 percent by August 1, 2023.

NEW. Incremental system RA requirements arising from generation retirement in the future shall be allocated to all LSEs within the three IOU TAC areas.

NEW. The MW value of the resources offered for compliance with the incremental procurement requirement will be the NQC or ELCC calculated based on the calculation methodology in place at the time the LSE made an irrevocable commitment to procure the resource.

NEW. LSEs may trade their compliance obligations subject to protocols to be developed in workshops following the effective date of this decision.

Ordering Paragraphs:

3. The following load-serving entities shall procure at least the amount of capacity in megawatts (MW) qualifying as system resource adequacy and for purposes of renewable integration as defined in Public Utilities Code Section 454.51, with at least ~~60~~ 20 percent delivered by August 1, 2021, ~~80~~ 60 percent by August 1, 2022, and 100 percent by August 1, 2023:

NEW: Energy Division Staff shall expeditiously and through a public process commence development of a detailed assessment of system RA requirements for 2021-2024 in coordination with the CAISO and stakeholders.

NEW: Energy Division Staff shall hold workshops within 90 days of the effective date of this decision to address implementation of the requirement and shall address, among other things: (1) counting of incremental import RA resources; (2) the use of September as a reference period for compliance counting; and (3) compliance trading among LSEs.

EXHIBIT B

Net Incremental Procurement Requirements Specified by Alternate Decision

Generator	Category	Proposed Retirement	2021	2022	2023	2024
Alamitos 3	OTC	12/31/2023	332.2	332.2	332.2	
Alamitos 4	OTC	12/31/2023	335.7	335.7	335.7	
Alamitos 5	OTC	12/31/2023	498.0	498.0	498.0	
Huntington 2	OTC	12/31/2023	225.8	225.8	225.8	
Redondo 5	OTC	12/31/2022	178.9	178.9		
Redondo 6	OTC	12/31/2022	175.0	175.0		
Redondo 8	OTC	12/31/2022	459.9	459.9		
Ormond 1	OTC	12/31/2021	741.3			
Ormond 2	OTC	12/31/2021	750.0			
OTC Subtotal			**3696.7**	**2205.4**	**1391.6**	
IOU	New Build	0.665	1596.0	2128.0	2660.0	2660.0
CCA	New Build	0.245	588.0	784.0	980.0	980.0
ESP	New Build	0.09	216.0	288.0	360.0	360.0
Incremental Subtotal			**2400.0**	**3200.0**	**4000.0**	**4000.0**
Total Procurement			**6096.7**	**5405.4**	**5391.6**	**4000.0**
Inland	Mothball		340.0	340.0	340.0	340.0
Sutter	Mothball		491.3	491.3	491.3	491.3
Reduction in Baseline			**831.3**	**831.3**	**831.3**	**831.3**
Net Incremental			**5265.4**	**4574.1**	**4560.3**	**3168.7**
Excess Procurement			**111%**	**83%**	**82%**	**27%**

EXHIBIT C

Net Incremental Procurement Requirements Assuming 4,000 MW Requirement and SCE Phase-In Methodology

Generator	Category	Proposed Retirement	2021	2022	2023	2024
Alamitos 3	OTC	12/31/2023	332.2	332.2	332.2	
Alamitos 4	OTC	12/31/2023	335.7	335.7	335.7	
Alamitos 5	OTC	12/31/2023	498.0	498.0	498.0	
Huntington 2	OTC	12/31/2023	225.8	225.8	225.8	
Redondo 5	OTC	12/31/2022	178.9	178.9		
Redondo 6	OTC	12/31/2022	175.0	175.0		
Redondo 8	OTC	12/31/2022	459.9	459.9		
Ormond 1	OTC	12/31/2021	741.3			
Ormond 2	OTC	12/31/2021	750.0			
OTC Subtotal			**3696.7**	**2205.4**	**1391.6**	
IOU	New Build	0.665	532.0	1596.0	2660.0	2660.0
CCA	New Build	0.245	196.0	588.0	980.0	980.0
ESP	New Build	0.09	72.0	216.0	360.0	360.0
Incremental Subtotal			**800.0**	**2400.0**	**4000.0**	**4000.0**
Total Procurement			**4496.7**	**4605.4**	**5391.6**	**4000.0**
Inland	Mothball		340.0	340.0	340.0	340.0
Sutter	Mothball		491.3	491.3	491.3	491.3
Reduction in Baseline			**831.3**	**831.3**	**831.3**	**831.3**
Net Incremental			**3665.4**	**3774.1**	**4560.3**	**3168.7**
Excess Procurement			**47%**	**51%**	**82%**	**27%**

EXHIBIT D

CalCCA Proposed Net Incremental Procurement Requirements
3,331 MW Requirement and SCE Phase-In Methodology

Generator	Category	Proposed Retirement	2021	2022	2023	2024
Alamitos 3	OTC	12/31/2023	332.2	332.2	332.2	
Alamitos 4	OTC	12/31/2023	335.7	335.7	335.7	
Alamitos 5	OTC	12/31/2023	498.0	498.0	498.0	
Huntington 2	OTC	12/31/2023	225.8	225.8	225.8	
Redondo 5	OTC	12/31/2022	178.9	178.9		
Redondo 6	OTC	12/31/2022	175.0	175.0		
Redondo 8	OTC	12/31/2022	459.9	459.9		
Ormond 1	OTC	12/31/2021	741.3			
Ormond 2	OTC	12/31/2021	750.0			
OTC Subtotal			**3696.7**	**2205.4**	**1391.6**	
IOU	New Build	0.665	443.0	1329.1	2215.1	2215.1
CCA	New Build	0.245	163.2	489.7	816.1	816.1
ESP	New Build	0.09	60.0	179.9	299.8	299.8
Incremental Subtotal			**666.2**	**1998.6**	**3331.0**	**3331.0**
Total Procurement			**4362.9**	**4204.0**	**4722.6**	**3331.0**
Inland	Mothball		340.0	340.0	340.0	340.0
Sutter	Mothball		491.3	491.3	491.3	491.3
Reduction in Baseline			**831.3**	**831.3**	**831.3**	**831.3**
Net Incremental			**3531.6**	**3372.7**	**3891.3**	**2499.7**
Fudge Factor			**41%**	**35%**	**56%**	**0%**

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements.	R.16-02-007 (Filed on February 11, 2016)

REPLY COMMENTS OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON PROPOSED DECISION REQUIRING ELECTRIC SYSTEM RELIABILITY PROCUREMENT FOR 2021-2023

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October 7, 2019

TABLE OF CONTENTS

Contents

Table of Authorities

Page

SUMMARY OF RECOMMENDATIONS

- ✓ Reject the California Independent System Operator's (CAISO's) request to increase the procurement to 4,700 megawatts (MW) unless and until a more rigorous and transparent analysis is performed.

- ✓ Allocate the incremental system Resource Adequacy (RA) requirement to all Load Serving Entities (LSEs) in the CAISO balancing area after confirming that the need is in fact a system RA need, and apply the same allocation principle in the future for system needs triggered by generation retirement in other transmission access charge (TAC) areas.

- ✓ Modify the phase-in of the incremental procurement requirement consistent with the recommendation by Southern California Edison Company (SCE)—20 percent for 2021, 60 percent for 2022 and 100 percent for 2023— recognizing the impracticality of the Proposed Decision's (PD's) proposed phase-in schedule and the higher costs associated with an increased implementation pace.

- ✓ Expressly identify the backstop procurement mechanism for failure by an LSE to meet its requirement and adopt tools to maximize the ability of LSEs to comply.

- ✓ Clarify the scope of the requirement by attaching a list of baseline resources and provide more detailed guidance on the determination of resource value for compliance purposes.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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REPLY COMMENTS OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON PROPOSED DECISION REQUIRING ELECTRIC SYSTEM RELIABILITY PROCUREMENT FOR 2021-2023

Pursuant to Rule 14.3 of the Commission's Rules of Practice and Procedures, the California Community Choice Association (CalCCA) submits these opening comments on the *Proposed Decision Requiring Electric System Reliability Procurement for 2021-2023* (Proposed Decision or PD).

I. INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

CalCCA continues to support the Proposed Decision's establishment of an incremental procurement requirement for 2021 allocated among load-serving entities in parallel with further analysis of the potential magnitude of any system resource adequacy (RA) shortfall. These Reply Comments recommend the following refinements in response to opening comments from other parties. CalCCA respectfully requests that the Commission:

- ✓ Reject the California Independent System Operator's (CAISO's) request to increase the procurement to 4,700 megawatts (MW) unless and until a more rigorous and transparent analysis is performed.
- ✓ Allocate the incremental system RA requirement to all Load Serving Entities (LSEs) in the CAISO balancing area consistent with the identification of the need as a system need, and apply the same system-wide allocation in the future for system needs triggered by generation retirement in other transmission access charge (TAC) areas.
- ✓ Modify the phase-in of the incremental procurement requirement consistent with the recommendation by Southern California Edison Company (SCE) recognizing the impracticality and higher costs associated with the PD's solution.

- ✓ Expressly identify the backstop procurement mechanism for failure by an LSE to meet its requirement and adopt tools to maximize the ability of LSEs to comply.
- ✓ Clarify the scope of the requirement by attaching a list of baseline resources and provide more detailed guidance on the determination of resource value for compliance purposes

Proposed Findings of Fact, Conclusions of Law and Ordering Paragraphs to conform the PD to these recommendations are provided in Appendix A.

II. THE RECORD DOES NOT SUPPORT THE CAISO'S PROPOSED 4,700 MW PROCUREMENT MANDATE

The CAISO encourages the adoption of its "operational analysis" as the baseline for a 4,700 MW incremental procurement requirement,[1] without clarifying key assumptions such as Operating Transfer Capability (OTC) capacity. While the PD's 2,500 MW mandate, based on only a rudimentary "stack analysis," comes close to the line of Commission authority under the "substantial evidence" standard, adopting the CAISO's proposal would cross that line.

Public Utilities Code section 1757(a)(4) requires the Commission to base its decisions on "substantial evidence in light of the whole record." Serious questions of fact have been raised in this proceeding without resolution or an opportunity for hearing: *e.g.,* the right metric to measure system RA requirements, assumed baseline resources, the amount of procurement in the pipeline, the availability of imports, and many other issues. Without an evidentiary record, the PD bases its decision solely on "hearsay *per se*," which the California courts have defined as "'documentary evidence that is introduced for the purpose of proving the matter stated in the writing'" that is "'not a statement by a person testifying at the hearing.'"[2] As the California Court of Appeal observed in *Oakley*, while the Commission admits hearsay in its proceedings, "'the mere admissibility of evidence does not necessarily confer the status of 'sufficiency' to support a finding *absent other competent evidence*.'"[3] Indeed, the *Oakley* Court was evaluating the sufficiency of a CAISO affidavit offered by PG&E to support the acquisition of a gas-fired powerplant in Oakley, California. The Court noted with particular concern that "the truth of the

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1 CAISO Opening Comments at 2.

2 *The Utility Reform Network v. Public Utilities Com*. (*Oakley*), (2014) 223 Cal. App. 4th 945, 959 (citations omitted).

3 *Id.* at 960 (emphasis in original).

CAISO's extrarecord statements is disputed."[4] While in this case, the CAISO itself is making its own argument, the argument remains untested by hearing.

The Commission is directing LSEs to invest billions of dollars in new generation resources over the next two to four years without any evidentiary record or opportunity for hearing. CalCCA continues to support further analysis more reflective of industry standard methods, such as loss of load probability studies. While CalCCA recognizes that a refined assessment may indicate different and perhaps greater needs, the Commission should reject the CAISO's proposed 4,700 MW system RA requirement unless and until the CAISO's assumptions and methodology have been examined with an opportunity for hearing.

III. THE PD PROVIDES NO RATIONAL BASIS FOR ALLOCATING THE INCREMENTAL PROCUREMENT REQUIREMENT SOLELY TO LSES IN THE SCE TAC AREA

Several parties seek to expand the allocation of the incremental procurement requirement from LSEs in the SCE TAC area, as the PD proposes, to LSEs in all three IOU TAC areas.[5] Despite the increase in burden for many Community Choice Aggregators (CCAs), CalCCA supports the broader allocation. All LSEs whose load could be affected by the system shortfall should share in the solution. This support is conditioned, however, on the Commission: (1) confirming through further analysis that the need is indeed a *system* (not *local*) need and (2) applying the same allocation to future system RA mandates arising from the retirement of plants in the Pacific Gas and Electric Company (PG&E) service territory.

The PD bases its discriminatory allocation on two factors: its observation that all of the OTC capacity that is set to retire is located in the SCE TAC area[6] and its hesitancy to require PG&E to procure additional capacity to add to an already-long position.[7] Neither line of reasoning is logically consistent with the proposed obligation to procure *system* RA across a mixture of LSEs with a wide range of as yet-unexamined RA net positions. The Commission should reject this proposal. If the Commission indeed confirms that the need is a *system* RA need, all LSEs responsible for meeting the system RA requirement in the CAISO balancing area

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4 *Id.* at 959.

5 *See, e.g.,* SCE Opening Comments at 3-8; Clean Power Alliance Opening Comments at 7-9.

6 PD at 33.

7 *Id.* at 32-33.

should contribute equitably to the resolution of any potential shortfall.[8] The Commission further must clarify that future system RA needs arising from retirement of existing plants will likewise be met by LSEs in all IOU TAC areas regardless, of the location of the generation whose retirement triggers the system need.

IV. SCE'S PROPOSED MODIFICATION OF THE PHASE-IN OF THE PROCUREMENT REQUIREMENT IS MORE REALISTIC AND WILL AVOID UNNECESSARY COSTS

CalCCA supports SCE's proposal to realign the procurement timeline for incremental resources, specifically, to require LSEs to bring 20 percent, 60 percent, and 100 percent of incremental resources online by 2021, 2022, and 2023, respectively.[9] As SCE points out, the PD's "compressed timeframe to procure resources and bring 60 percent online as early as August 1, 2021 is not practical."[10] In addition to SCE's concern regarding alignment of the PD's timeline with regulatory and procurement timelines, an overly aggressive, impractical timeline will saddle ratepayers with the higher costs of "urgency" development[11] without clear reliability benefits.

V. ANY ENFORCEMENT MECHANISM MUST BE SUPPORTED BY CLEAR BACKSTOP AUTHORITY AND TOOLS TO PROVIDE LSES COMPLIANCE FLEXIBILITY WITHOUT SACRIFICING RELIABILITY

SCE proposes an enforcement mechanism that imposes penalties on LSEs that fail to comply with the incremental procurement requirement. CalCCA agrees that mechanisms are necessary to ensure the requirements are met. Development of an enforcement mechanism, including compliance milestones, should follow a final decision directing procurement.

The Commission's primary focus in this decision, however, should be to clearly designate the backstop procurement mechanism and to provide tools to enable LSE compliance,

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8 Appendix B presents an allocation which, for illustrative purposes, is limited to Commission-jurisdictional LSES.

9 SCE Opening Comments at 11-12.

10 *Id.* at 11.

11 Many LSEs have aligned their new resource procurement with the declining federal solar tariff schedule, resulting in significant net capacity from hybrid solar and storage resources already contracted to begin deliveries in 2022. The tariff schedule, along with the generally rushed development timeline for new resources coming online in 2021, could result in total project costs as high as twice the cost of new resources brought online in 2022.

including the establishment of clear compliance rules. CalCCA supports the PD's conclusion that the Cost Allocation Mechanism or a similar mechanism should be used if, and only if, an individual LSE fails to meet its requirement based on later-adopted milestones.[12] The Commission further should provide for tradability of obligations, as proposed in CalCCA's Opening Comments,[13] as well as the proposal of the Alliance for Retail Energy Marketing for a temporary resource substitution provision in the event of a project delay of up to six months.[14]

VI. THE COMMISSION SHOULD CLARIFY ACCOUNTING RULES

The Commission should clarify the methodology for counting resources for compliance as follows:

- ✓ Append a list of baseline resources to the final decision to provide clear guidance on the definition of "incremental";
- ✓ Clarify the definition of "incremental" for import RA;
- ✓ Establish expeditious accounting rules for hybrid storage resources, which CalCCA believes represent the most promising preferred resource solution; and,
- ✓ Clarify that Net Qualifying Capacity and Effective Load Carrying Capability will be measured for compliance purposes based on September values.

These and other implementation issues should be addressed in workshops immediately following adoption of a final decision.

VII. CONCLUSION

For all of the foregoing reasons, CalCCA recommends the adoption of the recommended modifications to the Proposed Decision set forth herein.

October 7, 2019

Respectfully submitted,

Evelyn Kahl

Evelyn Kahl
Counsel to
California Community Choice Association

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12 CalCCA's Opening Comments pointed out, however, that the allocation within the CAM would require modification to address LSE-specific non-compliance. CalCCA Opening Comments at 12.

13 CalCCA Opening Comments at 11.

14 AReM Opening Comments at 14.

APPENDIX A

CalCCA Amended Findings of Fact, Conclusions of Law and Ordering Paragraphs

Findings of Fact:

16. The capacity of OTC plans subject to retirement by the end of 2020 is needed to maintain system reliability beginning in 2021 until ~~In addition to extension of 2,500 to 3,750 MW of OTC capacity, another~~ 2,500 MW of incremental system resource adequacy ~~and renewable integration resources~~ will be needed ~~by Summer 2021,~~ as a "least regrets" amount necessary to ensure system reliability.

Conclusions of Law:

~~8. Because the OTC units currently set to retire by December 31, 2020 are all within the SCE TAC area, it is reasonable for the Commission to require that all incremental procurement be conducted by LSEs serving load in that same geographic area.~~

8. Because incremental RA capacity is needed to meet system needs, it is reasonable for the Commission to allocate responsibility for this procurement to LSEs, solely on behalf of the customers they serve, in all IOU TAC areas.

NEW. Incremental system RA requirements arising from generation retirement in the future shall be allocated to all LSEs within the three IOU TAC areas.

12. The Commission should base the allocation of procurement responsibility for system resource adequacy and renewable integration-capacity to LSEs ~~within the SCE TAC area~~ based on the 2018 IEPR load forecast, adopted by the CEC in February 2019, with the 2021 projected load shares identified in Form 1.1c, "California Energy Demand Update Forecast 2018-2030, Mid Demand Baseline Case, Mid Additional Achievable Energy Efficiency and Additional Achievable
Photovoltaics."

13. As required by § 454.51(c), the costs of an IOU's ~~SCE~~'s procurement required by this decision should be allocated on a non-bypassable basis to all of the IOU's ~~SCE~~ customers as of the effective date of this decision and recovered through the Power Charge Indifference Adjustment on a vintaged basis.

23. IOUs~~SCE~~ should be authorized to consider third-party ownership and utility ownership of resources to be procured to satisfy the requirements of this order, but should be required to show that any utility-owned resources represent least cost to ratepayers, utilizing Appendix A, Section 2c, of D.19-06-032 as a starting point.

24. IOUs~~SCE~~ should be required to include ~~its~~ bid evaluation metrics and comparison metrics between third-party and utility-owned resources, in ~~its~~ advice letter(s) submitted for approval of the resources procured in response to this decision.

NEW. The MW value of the resources offered for compliance with the incremental procurement requirement will be the NQC or ELCC calculated based on the calculation methodology in place at the time the LSE made an irrevocable commitment to procure the resource.

NEW. LSEs may trade their compliance obligations subject to protocols to be developed in workshops following the effective date of this decision.

Ordering Paragraphs:

1. The Commission recommends that the State Water Resources Control Board extend the once-thru-cooling compliance deadlines the Alamitos and Huntington Beach plants for up to three years of at least 1,400 ~~2,500~~ megawatts (MW) ~~and up to 3,750 MW of capacity, of units with current compliance deadlines of December 31, 2020,~~ in order to allow time for new clean electricity capacity to come online.

2. All ~~The following~~ load-serving entities shall procure at least the amount of capacity in megawatts (MW) of qualifying as system resource adequacy equal to their load share of 2,500 MW ~~and for purposes of renewable integration as defined in Public Utilities Code Section 454.51~~, with at least 20 ~~60~~ percent delivered by August 1, 2021, 60 ~~80~~ percent by August 1, 2022, and 100 percent by August 1, 2023:
a. ~~Southern California Edison Company, 1,745 MW;~~
~~b. Southern California Edison Direct Access (aggregated), 355 MW;~~
~~c. Apple Valley Choice Energy, 7 MW;~~
~~d. Clean Power Alliance of Southern California, 357 MW;~~
~~e. Lancaster Clean Energy, 17 MW;~~
~~f. Pico Rivera Innovative Municipal Energy, 5 MW;~~
~~g. Rancho Mirage Energy Authority, 9 MW; and~~
~~h. San Jacinto Power, 5 MW.~~

6. ~~Southern California Edison Company (SCE)~~ The IOUs shall conduct an all-source solicitation to procure its obligation given in Ordering Paragraph 2a above and shall consider existing as well as new resources, demand-side resources, combined heat and power, and storage, as long as all resources are shown to be incremental to the baseline identified in Ordering Paragraph 5 above. ~~SCE~~The IOUs shall utilize the Demand Response Auction Mechanism contract as a starting point for negotiations with any demand response resources that bid into its solicitation.

7. ~~Southern California Edison Company (SCE)~~ The IOUs shall be authorized to propose utility ownership of a portion of the resources ~~it is~~ they are required by Ordering Paragraph 2a of this

decision to procure, and for that portion, shall abide by any existing procurement rules governing utility-owned resource participation in solicitations.

8. ~~Southern California Edison Company (SCE)~~ The IOUs shall present the results of ~~its~~ their solicitation required in Ordering Paragraph 6 above in one or more Tier 3 advice letters filed no later than January 1, 2021 and shall include the following information in ~~its~~ their advice letters:

9. For any procurement of resources that are new after the date of this decision, community choice aggregators with procurement obligations under Ordering Paragraph 2 of this decision and ~~Southern California Edison Company (SCE)~~ the IOUs shall enter contracts of at least ten years in length.

APPENDIX B

Illustrative Compliance Allocation Comparison
SCE-Territory Only and All LSEs

Planning Area	Agency	2021 Load Share	Compliance Obligation (NQC) if Statewide	Compliance Obligation (NQC) if SCE-Only
PGE	PG&E Bundled	19.39%	484.6	
	PG&E DA	5.29%	132.2	
	CPSF	1.90%	47.4	
	EBCE	3.31%	82.8	
	KCCP	0.02%	0.6	
	MCE	2.91%	72.7	
	MBCP	1.91%	47.8	
	PCE	1.83%	45.7	
	Pioneer	0.61%	15.3	
	RCEA	0.36%	8.9	
	SJCE	2.58%	64.5	
	SVCE	2.24%	55.9	
	SCP	1.44%	36.0	
	VCE	0.42%	10.5	
	PG&E Total	44.20%		
SCE	SCE Bundled	32.03%	800.8	1746.1
	SCE DA	6.51%	162.6	354.6
	AVCE	0.13%	3.2	6.9
	CPA	6.55%	163.7	356.9
	LCE	0.31%	7.8	17.1
	PRIME	0.09%	2.2	4.7
	RMEA	0.16%	4.0	8.6
	SJP	0.09%	2.3	5.0
	SCE Total	45.86%		
SDGE	SDG&E Bundled	7.92%	198.0	
	SDG&E DA	1.98%	49.5	
	Solana Beach	0.03%	0.9	
	SDG&E Total	9.93%		
Total			2500.0	

*Green highlighted cells indicate Community Choice Aggregators.

**Does not address potential allocation of requirements to other LSEs in CAISO balancing area.

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OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements.	R.16-02-007

REPLY COMMENTS OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON ASSIGNED COMMISSIONER AND ADMINISTRATIVE LAW JUDGE RULING INITIATING PROCUREMENT TRACK AND SEEKING COMMENT ON POTENTIAL RELIABILITY ISSUES

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TABLE OF CONTENTS

Pages

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements.	R.16-02-007

REPLY COMMENTS OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON ASSIGNED COMMISSIONER AND ADMINISTRATIVE LAW JUDGE RULING INITIATING PROCUREMENT TRACK AND SEEKING COMMENT ON POTENTIAL RELIABILITY ISSUES

California Community Choice Association (CalCCA) submits these comments in response to comments filed by parties in the *Assigned Commissioner and Administrative Law Judge's Ruling Initiating Procurement Track and Seeking Comment on Potential Reliability Issues*, issued on June 20, 2019 (Ruling), and the July 25, 2019, E-mail Ruling Partially Granting California Community Choice Association Request for Extension of Time to File Reply Comments.

I. INTRODUCTION AND SUMMARY

CalCCA joins the Energy Division Staff, the California Independent System Operator (CAISO), the investor-owned utilities (IOUs) and other parties supporting an immediate, focused assessment of near- to medium-term reliability risks. Many stakeholders agree directionally that a risk to reliability may be looming, although they differ in assumptions and conclusions regarding the timing and magnitude of the resource adequacy (RA) need. Like many of these stakeholders, CalCCA recommends the development of a more stable and deliberate analytical process to draw more reliable conclusions. Ratepayers deserve an approach that rests on a reasonably high level of confidence in the methodology, assumptions and outcomes, recognizing that a signal of shortage to the market will increase prices and drive up rates.

CalCCA appreciates that the Commission cannot stand idly by while a more rigorous analysis is undertaken. CalCCA thus proposes a "least regrets" strategy by beginning to pursue available existing resources and removing barriers to the development of new resources. The following measures can provide a foundation for this strategy:

- Provide notice to LSEs that new resources are likely to be needed in the 2021-2023 timeframe, even if the precise amount is not now known;

- identify and compare resource options for addressing the shortfall on the basis of feasibility, contribution against the deficiency, ratepayer and LSE cost, and consistency with the state's energy loading order;

- Continue to pursue CAISO's recommended extension of OTC deadlines for the existing Alamitos facility to maintain optionality as system reliability deficiency and resource options are analyzed, with contracts that minimize any incentives for the plant to run unless needed for reliability;

- Work with the CAISO and the IOUs to streamline permitting and interconnection requirements for new facilities to expeditiously ramp up the capability of new and existing preferred resources to provide reliability services while ramping down the CAISO's reliance on non-preferred resources;

- Request that LSEs to identify all resources currently mothballed or scheduled to retire or move to mothballed status, and all resources with contracts that will terminate from 2021 through 2023; use this list to create a clear signal to all LSEs that these resources are available and potentially needed, providing all LSEs an opportunity to contract before defaulting to central procurement; and

- Maximize the availability of import RA and ensure the "firmness" of these resources, including completing a rigorous analysis of the availability of import capacity, taking into account the most current data, and working in conjunction with the resource adequacy proceeding in front of the Commission and at the CAISO.

Taking these parallel paths – a more rigorous analysis and a "least regrets" strategy – will mitigate reliability risk while pursuing a more effective deliberate process to identify system needs.

II. A MORE STABLE AND DELIBERATE PROCESS IS REQUIRED FOR ASSESSING AND FRAMING DIRECTIVES TO MEET RESOURCE ADEQUACY NEEDS

Two major themes emerge from the comments: parties require further information on the mechanics of the Staff analysis, and the analysis as described lacks the rigor necessary for a procurement directive. Questioning the rigor of the analysis, TURN concludes it "is not yet convinced" there is any particular need for increased resource adequacy capacity in 2021, "but remains open to the possibility."[1] The CAISO questions the effectiveness of a stack analysis and declines to use Staff's approach, creating its own analysis.[2] SCE similarly departs from the Staff analysis to reach its own conclusions.[3] Yet other parties suggest that the appropriate analysis should rely on the SERVM model developed in this IRP process.[4]

Despite these differences, two important conclusions can be drawn. First, a more deliberate process for responding to the questions the Ruling poses should be developed. These important issues must be analyzed systematically and consistently to ensure that California reliability stays on track without interruption. Second, and in parallel with the "least regrets" strategy outlined above, any urgent new resource procurement targets should be supported by a greater depth of information and analytical rigor[5] if the Commission "wishes to order procurement with authority and credibility."[6]

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1 Comments of The Utility Reform Network (TURN Comments) at 3.
2 Comments of the California Independent System Operator Corporation (CAISO Comments) at 3.
3 Opening Comments of Southern California Edison Company (SCE Comments) at 5.
4 Comments of the Public Advocates Office (Public Advocates Comments) at 3; Opening Comments of the Alliance for Retail Energy Markets (AReM Comments) at 4.
5 *See, e.g.*, Comments of Western Power Trading Forum at 3-4, 11.
6 TURN Comments at 3.

III. ANALYSES PRESENTED BY STAKEHOLDERS AGREE DIRECTIONALLY THAT THE MARKET IS TIGHTENING BUT DISAGREE ON THE MAGNITUDE AND TIMING OF ADDITIONAL NEED

A. The Ongoing Retirement of Natural Gas Resources Creates a Need for Substantial New Development Over Time

Several stakeholders pointed to announced retirements of natural gas resources, including the Inland Energy Center noted by CAISO and SCE,[7] resulting from downward pressure on energy market prices associated with new renewable generation. These trends are likely to continue, signaling a need for replacement resources or re-contracting with existing resources to the extent they are economical and do not conflict with meeting the State's environmental goals. To ensure that California maximizes its ability to choose resources from the top of the loading order, it will be critical to fully understand anticipated natural gas resource retirements and their impact on reliability. CalCCA supports the development of a coherent framework and strategy to manage the retirement of the natural gas fleet, and, wherever possible, replace retiring capacity with cost-effective preferred resources. In particular, CalCCA reiterates its recommendation that the natural gas retirement study scoped for the 2019-2020 IRP cycle should develop a detailed analysis of what resources should be deployed, where, and when, in order to minimize the state's reliance on economically fragile natural gas plants.

B. Import RA Availability Remains a Pivotal Assumption in All Analyses But Parties Differ In Their Conclusions

The use of imports for RA remains a pivotal but uncertain component in the procurement proposal presented in the Ruling. Parties to the proceeding have presented markedly different views on the availability and reliability of imports. At one end of the assessments, parties foresee a significant risk to reliability in the near- to medium- term; at the other end, parties recognize a potential risk but find it is more easily managed. Most parties recognize the

[7] SCE Comments at 10-11.

importance of the question of the availability and reliability of imports, but are unable to state definitively whether out-of-state sources will be adequate and recommend additional study.[8]

A few conclusions may be reached from the many comments and themes therein. One is that parties differ sharply in their assessment of how much out of state capacity may be willing and available to enter into RA contracts. Two, parties differ in their analysis of the "reliability" of the import RA that they acknowledge is available, and whether there should be an arbitrary "de-rating" of import RA by 1/3, regardless of any evidence of a risk failure of RA import capacity to be available when called.

CalCCA echoes the comments it made in the RA proceeding- further analysis is needed to identify the magnitude of the potential impact import RA will have on reliability in the future, and when the effects of this impact will likely be realized.[9] CalCCA is firmly committed to the State's overarching goal of system reliability. We also hope the Commission can find the "sweet spot"—where requirements for participation in California's RA market are adequate to ensure that real resources are actually available in times of need, but do not unnecessarily discourage the use of this important category of resources to meet system needs.

1. Parties are Calculating "Import RA" in a Variety of Ways

On one end of the spectrum, SCE suggests "[i]t is not realistic to rely on imports in excess of historical levels to meet future system RA requirement."[10] SCE assumes the availability of only 4080 MW of "reliable" imports, plus 920 MW of SCE's share of Palo Verde and Hoover as "potential" imports.[11] The Public Advocates Office similarly constrained imports

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[8] *See, e.g.*, Comments of City and County of San Francisco (CCSF Comments); Opening Comments of Pacific Gas & and Electric Company (PG&E Comments); Comments of San Diego Gas & Electric Company (SDG&E Comments).

[9] Comments of California Community Choice Association on *Assigned Commissioner's Ruling Seeking Comment on Clarification to Resource Adequacy Import Rules*, July 19, 2019 at 5.

[10] SCE Comments at 29.

[11] *Id*. at 25.

to 4,000 MW in its analysis.[12] The CAISO, however, observes that historical levels of RA imports do not reflect potential RA supply because if currently uncontracted imports can be contracted for RA, much of the reliability need can be addressed.[13] Staff, although raising concerns, makes no particular assumption but observes that the need for import reliance will be around 8800 MW by 2021;[14] CAISO notes that Staff's concerns about relying on imports up to the MIC may be misplaced if currently uncontracted resources can be brought into a more rigorous RA contracting framework.[15]

2. Parties Question the Level of "Firmness" Required

Stakeholders raised questions relating to the level of firmness that will be required to ensure import RA ,[16] and many noted the need for improved rules. Public Generating Pool states that "import resources are being under-procured because there are several obstacles in the current RA program that prevent further procurement of import capacity."[17] Several parties note the close connection to the RA proceeding and recommend that questions regarding use of imports for RA be addressed in that proceeding.[18] CalCCA recommends integrating the import discussion here with the discussion on eligibility requirements in R.17-09-020.

C. All Analyses Deserve to Be Vetted Publicly

Addressing highly technical analyses in a ruling and comments fails to facilitate a shared view of the problem. Each approach deserves to be vetted publicly to enable the development a foundation of shared understanding of assumptions and conclusions. CalCCA recommends the Commission convene workshops to begin this process, centering on the most well developed

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12 Public Advocates Comments at 2.
13 CAISO Comments at 9.
14 *Assigned Commissioner and Administrative Law Judge's Ruling Initiating Procurement Track and Seeking Comment on Potential Reliability Issues*, June 20, 2019 at 12.
15 CAISO Comments at 17.
16 *E.g.*, Comments of Calpine Corporation (Calpine Comments) at 7.
17 Comments of the Public Generating Pool (PGP Comments) at 3.
18 *E.g.*, PGP Comments at 5; Comments of the California Large Energy Consumers Association (CLECA Comments) at 5.

analytical approaches, including those already developed in the IRP modeling process as well as those advanced by Staff, the CAISO and SCE. Pending this step, CalCCA offers the following initial observations on the analyses presented in opening comments.

1. Staff's Analysis

Staff makes a number of assumptions in developing its analysis that are not transparent to other parties; workpapers were not produced, and the bases for assumptions are not fully explained. Several parties join CalCCA in noting that their inability to review the actual supporting analysis performed by the Energy Division hampers their ability to comment on the Ruling and respond to the questions posed.[19] SDG&E notes that no analysis was provided regarding whether the volume and type of additional system procurement proposed in the Ruling provides the least-cost solution to ratepayers to address any market power concerns.[20] CLECA observes is not clear how the Commission came up with the figure of 500 MW for the proposed procurement by Southern California Edison, nor how it arrived at the August 1, 2021 date.[21]

CalCCA also voices concern that Staff's analysis may be more in the nature of a "back of the envelope" calculation without roots in available modeling tools, such as those developed in this proceeding. Other parties share this concern. CLECA notes that the models used by the Commission seem to be unable to perform analysis on the increasing need for ramping capability.[22] City and County of San Francisco comments that the Ruling predicates procurement not on a new "analysis" of publicly available data, but rather on "simple math" and not system modeling.[23] The Public Advocates Office actually reruns the calculations proposed in the Ruling with the most current information available, and recommends the Energy Division re-run RESOLVE and SERVM with a more conservative hourly constraint.[24] The Public

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[19] Opening Comments of NRG Energy, Inc. (NRG Comments) at 12; CLECA Comments at 3.
[20] SDG&E Comments at 2.
[21] CLECA Comments at 13.
[22] *Id*. at 6.
[23] CCSF Comments at 2.
[24] Public Advocates Comments at 2-3.

Advocates Office also recommends further study of the loads and resources available in the WECC.[25]

NRG puts this into perspective by noting the Commission is now considering directing new procurement based on what appears to be far less involved analysis and without any of the rigorous modeling that went into the first procurement-less IRP cycle.[26] AReM goes so far as to note that the proposals are "based on an oversimplified analysis" that is inconsistent with the more detailed studies and modeling employed for the IRP process and the CAISO, which studies and models do not support the Ruling's proposed procurements. [27]

The CAISO's comments are particularly instructive, pointing out that significant developments occurred after the Energy Division conducted its analysis. In particular, CAISO states that General Electric announced on June 20, 2019 that the 750 MW Inland Empire Energy Center will retire December 31, 2019.[28] CAISO expressed concern that the Staff's analysis fails to reflect the capability of the projected resource adequacy fleet to serve load after the gross peak hours, based on operational performance rather than static capacity values.[29] According to the CAISO, this is a significant omission because of the impact on sequencing of renewable integration and reliability.[30] The CAISO also notes that additional resources that are under development by the LSEs are not visible to the Commission or the parties.[31] Thus, Staff's analysis is both missing critical operational detail and an accurate assessment of resource availability.

Stakeholders should come together to form a reasonably shared view of near- and medium-term reliability threats. To inform this view, however, requires the transparency of all

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25 *Id*. at 3.
26 NRG Comments at 11.
27 AReM Comments at 2.
28 CAISO Comments at 3.
29 *Id.* at 3.
30 *Id*. at 11.
31 *Id*. at 10.

models and assumptions. Staff should therefore produce its workpapers or, at a minimum, present its assumptions and conclusions in a workshop.

2. California Independent System Operator Analysis

The CAISO concludes that without action, there is a "strong potential for insufficient resources" by 2021,[32] especially in the hours immediately after the gross peak hour, when loads remain high but solar production rapidly decreases. CAISO urges that the Commission prioritize procurement of existing and new resources to be online as soon as possible and, as a backstop, facilitate extending the OTC regulations for gas-fired resources needed to maintain near-term reliability.[33] CAISO also argues that the Commission should not discount imports to only one-third of stated capacity to account for a perceived risk, but rather strengthen and enforce the resource adequacy program.[34]

While CalCCA agrees with CAISO's recommendation regarding discounting imports, and does not immediately challenge CAISO's conclusions, a better understanding of the CAISO's approach and assumptions is required. Most importantly, the CAISO has advanced a new, untested paradigm for assessing reliability needs. With the exception of flexible, resource adequacy needs have been based on the forecast coincident peak loads; these analyses implicitly assume that if sufficient resources are available at the peak, resources will be sufficient in other periods as well. CAISO's approach challenges that assumption as a result of its conclusion that the system peak will be moving later in the day by 2022, and that certain resources (*i.e.*, solar resources) will not be available during those hours or in post-peak periods.[35]

In addition, CAISO's analytical approach does not count the Commission-approved NQC values for hydro or pump storage resources, instead opting to use average production mostly during a severe drought (2013–2018), without allowing for the possibility that the resources

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32 CAISO comments at 1.
33 *Id*.
34 *Id*. at 17.
35 *Id*. at 5-6.

could be redispatched to meet the load need in the absence of previously available but now retired resources. The rationale and data supporting CAISO's analysis should be made available to all parties.

CalCCA notes that CAISO's shift to consider hours outside of peak to identify the specific operational needs echoes CalCCA's call for much greater specificity in modeling approach to identify which resources, technologies, locations, and timing would most effectively address shortfalls caused by natural gas retirements.

CalCCA recommends that the CAISO provide greater transparency of its assumptions and analytical process. If, in fact, it is time to make the significant paradigm shift its analysis contemplates, a much greater level of public discussion is required.

3. Public Advocates Analysis

Public Advocates revised the Staff analysis "using the latest inputs to the 2019-2020 IRP model and included the 2018 average import level of 4,000 MW to assess what the additional resource would be if this 4,000 MW historical level were exhausted."[36] The analysis assumes a lower level of resources through September "partly due to data availability limitations," which it does not fully explain.[37] Using its analysis, it concludes that there could be an additional need of 5223 MW above the 4,000 MW historical level, which it states would exceed estimated Maximum Import Capability (MIC).[38] Public Advocates states that the MIC level for 2019 is "Total Import Capacity to be Shared" is 6,193.8 MW, but the document that they reference indicates that the "Total Import Capacity to be Shared" for 2019 is actually 5,887.8 MW. This number ignores additional MIC available to loads inside the control area through existing transmission contracts and Pre-RA Import Commitments. The actual amount of MIC is shown as "Available Import Capability (for loads in the control area)" and is actually 10,193.4 MW for

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[36] Public Advocates Comments at 2.
[37] *Id.*
[38] *Id.*

2019 and 10,753.4 for 2020.[39] It recommends, however, that the Staff model future system RA capacity based on this conservative import value "using RESOLVE and then modeling the resulting portfolio in SERVM to ensure its reliability…."[40]

As with the other analyses presented in the Ruling or comments, the Public Advocates Office leaves more questions than it answers. Most importantly, Public Advocates Office admits they did not include in their analysis all resources expected to be available, including some of the OTC replacement resources.[41] Moreover, while suggesting a conclusion regarding the potential additional need, the Public Advocates Office comments also appear more aimed at providing input to how a more deliberate analysis should be performed.

4. Southern California Edison Company's Analysis

SCE concludes that "the expected system RA shortfall is likely to be 5,500 MW or more in 2021, and continue over the next several years."[42] SCE's analysis, like other skeletal analyses presented in this process, requires further explanation to enable a complete understanding of its assumptions and conclusions. SCE's focus, however, is on the pivotal variables: OTC compliance dates, retirements of non-OTC thermal generating units, shifting peak load, reductions in effective load carrying capability (ELCC) values, uncertainty in import availability and resulting thinner capacity margins.[43] Without a clear-eyed assessment of these unknowns, SCE's overall conclusions are largely grounded in speculation.

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39 *Id.* at 2, citing to http://www.caiso.com/Documents/Step6-.2019AssignedandUnassignedRAImportCapabilityonBranchGroups.pdf. Values for 2020 are in http://www.caiso.com/Documents/Step6-2020AssignedandUnassignedRAImportCapabilityonBranchGroups.pdf.
40 *Id.* at 1.
41 *Id.* at 2.
42 SCE Comments at 5.
43 *Id.* at 10-13.

CalCCA looks forward to further exploring SCE's conclusions, but offers several initial observations:

- ✓ SCE takes an unjustifiably conservative approach, absent further examination, to counting import availability, which it limits to 4,080 MW of "reliable" imports,[44] plus 920 MW of SCE's share of Palo Verde and Hoover as "potential" imports.[45]
- ✓ SCE does not make clear if it has included pumped storage resources which, if omitted would represent approximately 1,400 MW of NQC.

For these and other reasons, SCE's analysis warrants further review before relying on it as a basis for a specific procurement directive.

Beyond SCE's technical analysis, however, the utility draws baseless conclusions seemingly aimed at cementing itself in the position of central buyer. SCE states:

> It will be very difficult for approximately 40 LSEs to simultaneously solicit, procure, and develop 2,000 MW of incremental RA capacity by August 1, 2021, given the market confusion that will likely occur as dozens of buyers compete for limited new resource project options and the fact that normal development lead times for new projects typically exceed the time available between now and August 2021.[46]

SCE has virtually no basis for this statement. CalCCA submits that the problem is not the number of buyers in the market, as those conditions are present in many functional markets. The error of SCE's claims that the LSEs in the market cannot meet these needs is demonstrated in the fact that at least one group of LSEs have in fact already made progress on addressing the shortfall: the CCAs. As noted in our opening comments, since the development of the baseline resource list used by Energy Division, CCAs have collectively contracted for over 2,000MW of new resources, with approximately 200 MW of NQC already contracted for online dates in 2021.[47] Some CCAs indeed have already procured more NQC than their load share responsibility.

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44 *Id*. at 15.
45 *Id*.
46 *Id*. at 7.
47 Opening Comments of California Community Choice Association at 11.

Further, SCE provides no demonstration that it would be able to procure the needed resources by August 1, 2021. Indeed, SCE states that the current procurement and resource development processes will not support significant incremental resource capacity coming online by August 2021.[48]

IV. MORE DETAILED AND PUBLIC ANALYSES ARE NECESSARY FOR THE COMMISSION TO DIRECT ANY NEEDED PROCUREMENT WITH CREDIBILITY AND AUTHORITY

Opening comments are striking for the absence of any strong compulsion for moving ahead with very specific action without any further thought. CalCCA thus proposes that the Commission establish a timeline and framework for further analysis.

To begin to bring together a shared understanding of near- and medium-term reliability deficiencies, CalCCA proposes the Commission schedule workshops over the next month to explore the analyses advanced by the Staff, CAISO, SCE, and others, including a detailed review of the relevant workpapers. The aim of these workshops would be for stakeholders to discuss and form a consensus on the target period to be analyzed, demand forecasts, baseline resource availability, an appropriate analytical approach, key assumptions (including a focused consideration of import availability), and other issues. Following modeling by CAISO in coordination with Commission Staff, data should be reviewed by stakeholders in a separate workshop.

A. Target Period

The Staff analysis focused closely on the 2021-2022 time period. Other parties have suggested, however, that the concerns are not limited to this period.[49] Determining the appropriate window for analysis is a critical foundation for developing a shared outlook.

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48 SCE Comments at 6.
49 CAISO Comments at 2; SCE Comments at 27.

B. Baseline Resource Availability Scenario

Stakeholders differ significantly on what resources are likely to be available in 2021 and, consequently, which resources would be "new" or incremental to that baseline resource list. A common set of baseline resources, including consideration of near- or medium term retirements, is a necessary foundation to any analysis. Developing this resource list should consider the range of uncertainty around (1) OTC retirement schedules; (2) potential retirement of non-OTC thermal generation; (3) import availability; (4) hydro availability; (5) other availability or use limited resource scenarios and (4) new resources, based on an assessment of resources currently in the CAISO queue.

C. Analytical Model

The Staff uses a simple "stack" analysis to assess near- and medium-term reliability. As noted above, SCE departs from this approach with far more restrictive assumptions about unavailability of RA imports and other aggressive assumptions. The CAISO shifts gears entirely, apparently using an entirely different methodology that focuses beyond coincident peak, which until now has been the focal point of system reliability assessment. Finally, the Public Advocates Office and AReM suggest relying on the IRP SERVM model to conduct the analysis. General agreement on an analytical model is another critical foundation to building a common outlook.

D. Key Assumptions

Modeling assumptions will have a material impact on the output of any model. Key modeling assumptions that should be developed include, at a minimum: load levels for the hours to be studied, hydro conditions, Non-CAISO loads and resource availability, Net Qualifying Capacity determination, Effective Load Carrying Capability, resource retirements, and Distributed Energy Resource growth.

E. Import RA Availability

All analyses and nearly every stakeholder has acknowledged the pivotal role that import RA will play in determining near- or medium-term reliability outcomes. The availability and willingness of generators who offer energy into California to commit to firm RA contracts is a critical factor in evaluating whether and how significant a reliability deficiency California actually faces. CalCCA presents in Section V a proposal to accelerate making the supply of import RA more transparent.

F. Other Issues

Other topics that may have an impact on any final conclusion regarding deficiency include the effect of withholding. As the City and County of San Francisco notes, the Ruling and accompanying directive fail to address the concern that certain entities may be withholding capacity from the market, and therefore fail to distinguish "between actual load needs and the perception of insufficient capacity to meet those needs that withholding creates.[50]

V. WHILE A MORE CAREFUL ASSESSMENT IS UNDERTAKEN, SEVERAL SOLUTIONS ARE AVAILABLE TO ENSURE A "LEAST REGRETS" OUTCOME

A. Specific Interim Measures Are Needed While Analysis is Performed

CalCCA proposes that the Commission direct four specific interim measures on a parallel path with further analysis. By implementing these measures, the Commission can be assured it is making progress toward securing reliability while a more definitive need is determined.

First, the Commission should give a clear signal that new resources are likely to be needed in the 2021-2023 timeframe, even if the precise amount is not now known. It should thus provide notice that LSEs should make every effort to begin exploring near-term possibilities while the analysis is completed. As noted above, some LSEs, especially CCAs, are already well advanced in this process of pursuing new resources. The Commission should also commence

[50] CCSF Comments at 8.

development of procedures for the allocation of any responsibility for new resource development or existing mothballed or scheduled to retire resources that arises out of its more rigorous analysis.

Second, the Commission should conduct a workshop-based process to identify and compare resource options for addressing the shortfall on the basis of feasibility, contribution against the deficiency, ratepayer and LSE cost, pollution impacts, and consistency with the state's energy loading order. CalCCA supports utilization of the state's energy loading order as an overarching policy guide to addressing this deficiency. While CalCCA recognizes the technical and implementation challenges of addressing an evening peak deficiency of such magnitude with preferred resources on such an expedite timeline, these resources should not be summarily dismissed as having the potential to contribute to addressing this shortfall. Instead, the Commission should conduct workshops to consider the feasibility, reliability contribution, cost, and environmental benefits of incorporating preferred resources into the solution set for any confirmed deficiency.

Third, the Commission should continue to pursue, in coordination with the CAISO, extension of the OTC deadline for the existing Alamitos facility to retain optionality in the event that further analysis of needs and solutions dictate the need for its continued operation. While CalCCA supports the ultimate and imminent closure of the state's remaining OTC facilities, it recognizes the inherent and unpleasant policy tradeoff between a brief extension of this OTC facility relative to the construction of new fossil generation should preferred resources be deemed insufficient to address a shortfall.

Tough choices will need to be made if resources higher in the loading order cannot be deployed within the necessary timeframe to secure reliability. Any plan to defer OTC retirement of Alamitos should contemplate a contracting structure aimed to minimize the facility's operations and consequent environmental impact on local air quality, climate progress and the aquatic environment. Specifically, CalCCA supports a contracting approach that would support this facility's operation while reducing or eliminating any financial incentive to operate, such as revenue from wholesale energy transactions.

Further, any OTC extension for Alamitos should include a clear exit strategy; for example, CAISO has previously studied the potential for demand response to reduce local capacity requirements. In a study as part of the 2018-19 transmission planning process, CAISO identified the potential for 500-600 MW of demand response/storage to reduce the local capacity requirements for the LA Basin and San Diego/Imperial Valley Local Capacity Areas.[51] Similar analysis should be performed for the other local capacity areas to target procurement of resource that can meet both local and system needs.

Fourth, the Commission should work with the CAISO and the IOUs to streamline permitting and interconnection requirements for new facilities. The state encountered a similar need for new resources following the retirement of SONGS in 2012 and loss of the Aliso Canyon Natural Gas Storage Facility later. In both cases parties working together were able to accelerate putting steel in the ground. The case of Aliso Canyon would be especially instructive because of its focus on non-natural gas unit solutions.

Fifth, the Commission should set a window during which all the CAISO and generators will identify all resources currently mothballed or scheduled to retire or move to mothballed status and contracts that will terminate from 2021 through 2023. A list should be developed of these status changes, contracts, and termination dates, and the Commission should set a contracting window during which any LSE may negotiate the short-term retention of these resources on behalf of its customers. By the time this window closes, the Commission should have completed a more rigorous analysis and be in a position to determine whether any further contracting is required. If so, either a central buyer or, if none has yet been selected, an IOU, should be directed to procure existing, needed resources for a term not to exceed three years on

[51] http://www.caiso.com/Documents/Presentation-2018-2019TransmissionPlanningProcessMeeting-Nov16-2018.pdf

behalf of all benefitting customers. As CalCCA discussed in its opening comments,[52] the Commission should not assume by default that only IOUs are in a position to re-contract with existing resources.

Finally, it will be important during this transition to both maximize the availability of import RA and ensure the reliability of these resources. A modified approach to the MIC could improve the transparency of import RA availability for planning purposes, for example, and as could be further developed by the CAISO, the CAISO could make MIC available on a three-year forward basis. Concurrent with this process, the Commission should continue its analysis of the impact of and any necessary changes to the rules for import RA, as CalCCA proposed in its recent Comments regarding the Resource Adequacy Import Rules.[53] Specifically, CalCCA urges that any refinement or clarification to existing interpretations of the Resource Adequacy Import Rules consider all available information and analysis, including that being considered in the Resource Adequacy proceeding in front of this Commission, and the CAISO stakeholder initiative.

B. CalCCA Recognizes Considerable Technical and Implementation Challenges to the Development of New Renewable Energy Projects Sufficient to Address a Multi-Gigawatt Shortfall.

Several parties believe new resources should be developed as a primary strategy to address deficiencies in 2021. Additional analysis is needed in the near term to determine whether new resources can be developed quickly enough to address deficiencies in 2021. CalCCA recommends working with the CAISO and other retail sellers to determine the range of capacity currently in the CAISO interconnection queue that is available to come only by mid-to-late 2021.

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52 Opening Comments of California Community Choice Association at 20.

53 Comments on California Community Choice Association on *Assigned Commissioner's Ruling Seeking Comment on Clarification to Resource Adequacy Import Rules*, July 19, 2019.

CCAs are actively developing a number of new solar, wind, and energy storage projects. While some projects have online dates in 2020-2021, many projects have commercial operation dates in 2022 and beyond. Due to practical aspects of project development timelines, meeting a very near-term capacity shortfall with new resources has many challenges. For a project to achieve operations by mid-to-late 2021, it must already have initiated the development process, which includes establishing a position in the CAISO queue, securing site control, and applying for required permits. Projects seeking to obtain full deliverability status no later than 2021 will likely need contracts to be executed no later than late November 2019 in order to satisfy the affidavit requirement. Developing a clear understanding of the number of projects well-positioned to meet these development milestones will be key for assessing overall capacity needs.

It is also important to recognize that LSEs will likely pay a premium for power purchase agreements with renewable energy and energy storage projects in order to accelerate the online to mid-to-late 2021. Import tariffs on solar modules imposed by the Trump administration have added costs to near-term project development and increased costs through the 2021 timeframe. Based on RFOs recently conducted by its member organizations, CalCCA estimates that accelerating online dates to mid-to-late 2021 for new solar energy projects could increase the overall contract cost by approximately 10% over the life of the project, compared to projects with commercial operation dates in 2022 or later.

At the same time, battery installation costs for standalone storage or storage coupled with renewable energy projects are forecasted to decline steeply going into 2022 and beyond. Storage project prices are also dropping quickly, making later installation dates cheaper. However, phasing out of the investment tax credit for solar and storage projects may make co-located storage projects more expensive. Taken together, the Commission should recognize that each of the potential options and timing may have significant cost implications.

C. The Commission Should Adopt a Methodology for Allocating Responsibility for Capacity, Not Cost, in the Medium-to Long-Term

In its comments PG&E suggests the Commission solicit from LSEs their forward procurement as of October 31, 2019, the use this data along with LSE load forecasts to identify the extent to which LSE's are fully procured to meet their load's capacity needs, and then allocate out cost responsibility for 500 MW of existing resource procurement and procurement responsibility for the 2,000 MW of new resources, to those entities with portfolio's that are not fully procured.[54]

CalCCA proposes instead to allocate the responsibility for new reliability resources to all load equally to reflect the equal contribution to the need for new marginal RA capacity as proposed in the Ruling. Ultimately, the need for additional capacity to be brought into the system or retained is caused by the collective impact of all load that contributes to system peaks. When load collectively exceeds the total system capacity, all peak load contributes equally to that shortfall.

While RA contracts secure commitments from generators to dispatch when called on, these contracts do not contribute to creating new generation because development decisions are not solely or primarily driven by the value of RA contracts. Since LSEs are not required to have all System RA under contract for a 2021 showing until much later in 2020, each LSE's current 2021 system RA position is only a reflection of whether the LSE happens to have entered into RA contracts early or not, and not the LSE's actual contribution to system shortfall. Even more significantly, open System RA positions in 2022 or 2023 System RA are only an idiosyncratic accident of the particular mix of RA contract terms. Thus, PG&E's proposal to use 2021 System RA positions is ultimately unworkable, and an LSE's RA position is not a reasonable proxy for how much the LSE's customers' energy usage is contributing to the need for new resources. The

[54] PG&E Comments at 4.

allocation of responsibility for new generation should turn to contributions to the peak loads driving the actual shortfall.

CalCCA notes the Commission, instead of engaging in a complex process of cost allocation and true ups across LSEs, should seek to ensure the right amount of capacity is brought online. CalCCA proposes an allocation of responsibility for *capacity*, not cost, to allow individual LSEs to decide how best to bring those new resources to fruition cost-effectively, whether from new build, RA imports, or contracting with retiring resources. This will allow some LSE to pursue new resources that will meet both their capacity and energy needs, and others to pursue RA only contracts with existing resources to meet their capacity needs.

CalCCA agrees with PG&E that the IOUs, which have more capacity than needed to serve their load, should be not be required to procure additional capacity just to meet RA regulatory requirements. The proposal of allowing LSEs to seek the most cost effective approaches would allow those LSEs that need new generation to serve load to pursue those and show the contribution to meeting the system RA shortfall, while IOUs that do not need new build generation, may contract with existing resources, either in state or as imports.

Finally, the Commission should also consider making these commitments tradeable, so that LSEs who have already met more than their share of this identified need could trade their compliance share with LSEs in need. This is particularly important for the CCA community as several CCAs have already satisfied their presumed share of the 2,000MW need with new procurement not reflected in the NQC list-based capacity stack analysis, while other CCAs are likely to be short given their recent (or upcoming) launch.

This approach of allocating capacity responsibility rather than cost responsibility preserves the competitive dynamic of having a multi-buyer marketplace for system RA and allows LSEs the autonomy to identify their own optimal solutions in coordination with their other portfolio needs. This compromise approach would both allocate responsibility fairly while not exacerbating issues of excess resources in IOU portfolios.

VI. THE COMMISSION SHOULD DEVELOP A COHERENT PROCESS FOR LSES TO MEET NEEDS

The Commission should be cautious to avoid making long-term decisions based on the issues forced by the current "crisis." Instead, CalCCA proposes that a methodical and iterative approach to the IRP process be developed independent of the current emergency measures.

CalCCA agrees with CESA that the IRP process needs a long-term framework for addressing needs in an orderly fashion based on careful development of the record. In this spirit, CalCCA proposes that the IRP procurement framework needs to adhere to the iterative model already established in D.19-04-040. This process needs to preserve LSE autonomy to pursue optimal resources for their customers and allow LSEs to first respond to needs identified in the prior cycle's modeling evaluation of the aggregate Hybrid Conforming Portfolios. Only if the failure of LSEs to meet needs or if new factors drive nearer term issues would other mechanisms be needed to address needs in the shorter term.

This approach suggests three distinct procurement mechanisms for each of three different time frames. First, for needs more than one IRP cycle into the future (*e.g.*, more than four years in the future), LSEs have the right of self-procurement to address their share of identified needs. For longer term needs, there would therefore be multiple opportunities to meet longer term needs across multiple cycles based on rigorous analysis of needs in SERVM or PLEXOS. If there are still outstanding needs, LSEs still would have to adjust course accordingly to address any shortfalls. Second, short and medium term needs (*e.g.*, under four years) would not allow for a full cycle of assessment of procurement plans, revision, and reassessment. These remaining residual needs could be addressed by a residual buyer framework of the kind contemplated in. R.17-09-020.

VII. CONCLUSION

For the reasons stated above, CalCCA recommends the development of a more stable and deliberate analytical process to create a high level of confidence in the analytical tools and outcomes. Pending the results of this process, CalCCA recommends the Commission employ a "least regrets" strategy to pursue available existing resources and remove barriers to the development of new resources.

August 12, 2019

Respectfully submitted,

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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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION COMMENTS ON PROPOSED DECISION ON WORKING GROUP 1 ISSUES 1-7 AND 11

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TABLE OF CONTENTS

TABLE OF AUTHORITIES

Page(s)

CPUC Decisions

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION
COMMENTS ON PROPOSED DECISION ON
WORKING GROUP 1 ISSUES 1-7 AND 11

Pursuant to Rule 14.3 of the Commission's Rules of Practice and Procedure, the California Community Choice Association (CalCCA)[1] submits the following comments on the proposed *Decision Refining the Method to Develop and True Up Market Price Benchmarks*, issued on September 6, 2019 (Proposed Decision or PD).

I. INTRODUCTION AND SUBJECT MATTER INDEX

The Proposed Decision addresses Power Charge Indifference Adjustment (PCIA) Scoping Memo issues related to the PCIA annual true-up (Issues 1-3), forecasting (Issues 4-5), the value of unsold resource adequacy resources (Issues 6-7) and billing determinants (Issue 11). It adopts certain proposals by CalCCA and Pacific Gas and Electric Company (PG&E), Working Group 1 (WG 1) co-leads, with modifications and decides two PCIA issues that remain unresolved by WG 1: (1) the price set for unsold Renewable Portfolio Standard (RPS) attributes and (2) the price set for unsold Resource Adequacy (RA) attributes.

CalCCA partly supports the Proposed Decision, but recommends the following modifications:

- ✓ The Commission should defer any decision on whether or how to include long-term fixed price power purchase agreements (PPAs) in the RPS benchmark until after conclusion of

[1] California Community Choice Association represents the interests of 19 community choice electricity providers in California: Apple Valley Choice Energy, Clean Power SF, Clean Power Alliance, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Monterey Bay Community Power, Peninsula Clean Energy, Pioneer Community Energy, Pico Rivera Innovative Municipal Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Jacinto Power, San Jose Clean Energy, Silicon Valley Clean Energy, Solana Energy Alliance, Sonoma Clean Power, and Valley Clean Energy.

a public process establishes that their inclusion will be feasible, consistent with D.18-10-019;

- ✓ All unsold RPS attributes should be valued at the RPS benchmark, recognizing the value of these attributes to bundled customers and ensuring consistency with D.18-10-019;
- ✓ All unsold RA attributes should be valued at the price floor set by the IOU in its sales process for such attributes to the extent the price floor exceeds the amount required to avoid penalties;
- ✓ For RA to qualify as unsold in calculating the market price benchmark, an IOU must offer that RA to the market by the end of August preceding the compliance deadline for the relevant year to avoid prejudice to other load-serving entities (LSEs). Otherwise unsold amounts are treated as retained and valued at the Market Price Benchmark (MPB), precluding a zero or *de minimis* valuation in the RA benchmark; and
- ✓ The Commission should clarify certain issues regarding forecasting and true up methodology.

Proposed changes to findings of fact, conclusions of law and ordering paragraphs are provided in Appendix A.

II. THE COMMISSION SHOULD ADOPT THE CO-LEADS' RECOMMENDATION TO BASE THE RPS ADDER ON INDEX PLUS TRANSACTIONS AND DEPART FROM THIS APPROACH ONLY IF A FEASIBLE METHODOLOGY IS ESTABLISHED THROUGH A PUBLIC PROCESS

The Proposed Decision adopts the co-leads' proposal for calculating the RPS Adder based on four quarters of Portfolio Content Category 1 index-plus contracts. CalCCA supports this portion of the Proposed Decision.

Additionally, however, the Proposed Decision finds: "Incorporating fixed-price bundled transactions into RPS Adder calculations is expected to produce more accurate results and is ultimately the proper approach."[2] The Proposed Decision further directs Staff "to propose a method to include long-term fixed-price transactions in calculating the RPS Adder by December 2020."[3] When read together, these portions of the Proposed Decision appear to commit the Energy Division Staff to developing a methodology to incorporate long-term fixed-price transactions into the RPS Adder, to take effect in 2021. While the PD itself recognizes "[t]here are technical challenges" to this approach — a fact acknowledged by TURN — it downplays

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2 PD, Finding of Fact 6 at 45.

3 PD at 12, and Ordering Paragraph 1(c), at 53.

those challenges. It further concludes that an index-plus approach will not reflect the evolution of the market toward long-term contracts.[4] As discussed below, the co-leads undertook extensive efforts to develop a method for including long-term fixed price contracts in WG 1. We found contrary to claims of greater accuracy, this approach would be technically challenging, and re-introduce the sort of administrative assumptions and non-market approaches to valuation that D.18-10-019 eschewed.

A. The Appropriate Input for the RPS Adder Is "Index Plus" Transactions

The co-leads proposed, and the PD adopts for 2020, the use of "index-plus" transactions as the appropriate input for the RPS Adder. Index-plus transactions have the following virtues:

- Index-plus is the current market standard method for transacting for RPS supply among IOUs and CCAs. This is how IOUs are selling from their portfolios.
- Index-plus deals are short-term, and so reflect current market prices for a particular delivery year, with none of the temporal complexity that long-term deals introduce.
- Index-plus deals explicitly price separately for energy and RPS, avoiding the need to tease the value of multiple attributes out of a single price.
- Index-plus deals are generally not generator specific, and so avoid the need to engage in project-specific analysis of a generation profile, or node-specific pricing analysis.

For the Final RPS Adder, the PD proposes to rely "on index-plus contracts executed in year (n-1), and the first through third quarter of year n for delivery in year n…."[5] CalCCA agrees with this approach, providing for the most recent data available to determine the RPS market price benchmark – a benchmark that is intended to reflect current market prices.

B. The Working Group Co-Leads' Extensive Efforts to Develop a Method for Including Long-Term Fixed-Price PPAs into the RPS Adder Led to the Conclusion that Doing So Is Infeasible

CalCCA and PG&E devoted substantial effort to incorporating long-term fixed-price transactions into the RPS Adder. We concluded that doing so was infeasible in light of

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4 PD, Finding of Fact 3 at 45.
5 *Id.*, Ordering Paragraph 3.a at 52.

D.18-10-019's requirements to use (a) recent, (b) market-based, (c) prices for particular power attributes.[6]

The mismatch between the D.18-10-019 framework and long-term fixed price contracts is fundamental. Decision18-10-019 requires valuation of individual attributes (brown power, an RPS adder, and an RA adder) for a particular time (year N) from recent contracts (executed within the last two years) for all types of generators. In contrast, long-term fixed-price PPAs, particularly for new construction, value all of the attributes from an individual power plant together at a single price for numerous years, even decades. There is no separate valuation of individual outputs — no separate RA price or RPS price or brown power price. Just a single $/MWh energy price. Further complicating matters, prices are held constant over many years (sometimes with periodic step-ups, more often not). And value for a particular project will depend on its location with the CAISO system and its generation profile. Teasing out point estimates of the value of individual attributes at a particular point in time from agreements for a bundle of attributes over a long period of time requires addressing and disentangling the temporal, locational, and technological factors in play for each PPA. We will take each of these concerns in turn.

Long-term fixed-price PPAs are, as the name implies, for a long term, and do not readily lend themselves to valuation for a single year. The parties who negotiated the deal may have offered a discount in early years in return for higher payments in later year, or vice versa, and there is no way to tell from the contract. Thus, to derive a value for a particular year requires the sort of administrative assumptions (*e.g.*, assumption of a discount rate, or a forward price curve) that D.18-10-019 was supposed to leave behind. There is also a temporal challenge. For new construction, there is often more than two years between the contract execution date and the expected commercial on-line date (COD). If we stay within the time limits imposed by D.18-10-019's stated desire to use recent transaction data (contracts executed no earlier than "n-2", in the parlance of Appendix A), many or even most long-term fixed-price PPAs will not be eligible for inclusion in the RPS Adder. Extend the time frame for inclusion, and you are no longer looking at just recent transactions. Moreover, any cut-off past n-2 (the last full calendar year for which data are available at the time of the rate forecast) is essentially arbitrary.

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6 *See* D.18-10-019, Appendix A.

Thornier still is the challenge of extrapolating the value of any one attribute from a contract that provides for *all* attributes for a single price. A long-term fixed-price PPA will generally provide for the entire output of a plant (energy, RPS, RA, and anything else) for a single $/MWh. It is impossible to determine from the PPA itself which portion of that price is attributable to energy, or green attributes, or RA, or other attributes. Doing so requires, again, the sort of administrative assumptions that D.18-10-019 was supposed to leave behind in favor of actual market transaction data. It requires subtracting out an administratively established energy value, and subtracting out an administratively established RA value converted from $kw/month to $/MWh using some selected estimated load carrying capacity value.

Finally, the type of generation and the location of the resource play a part in determining resource value. Renewable generators' output will vary substantially depending on the project technology type (*e.g.*, wind or PV solar) and the location of the project (insolation and wind characteristics vary materially depending on location). Prices also vary depending on the CAISO node at which a plant interconnects. Then there is the added complication of co-located storage. To address these variables again requires the type of administrative assumptions and simplifications (*e.g*., use of a generic generation profile, aggregation of nodal prices) and risks a mismatch with actual market structures that D.18-10-019 was supposed to leave behind.

Before the Commission concludes that inclusion of long-term fixed price PPAs in the RPS benchmark is feasible, much less the "better approach,"[7] further work is required. The Commission should substantially modify the PD's recommendations for gathering data and developing an alternate methodology, as discussed below.

C. Any Refinements to the RPS Benchmark Should Be Developed Through a Transparent Public Process

Even if conceptually incorporating long-term fixed-price PPAs into the RPS market price benchmark were *desirable* notwithstanding D.18-10-019's focus on recent market transactions for specific power attributes, the Commission should first establish that it is *feasible* within D.18-10-019's framework. As noted above, including long-term fixed price PPAs in the RPS benchmark is fraught with challenges. CalCCA recommends that the Commission undertake further public processes before determining that a new methodology will be employed for the

[7] PD, Finding of Fact 6 at 45.

2021 RPS Adder to ensure sufficient opportunity to understand and address the issues encountered by WG 1.

The Commission should invite Staff to develop a methodology for modifying the RPS benchmark to include long-term fixed-price PPAs *if and only if such a methodology can be squared with D.18-10-019*. The Proposed Decision should be revised to clarify that the December 2020 date is a deadline for Staff to put forward its proposal, rather than a date for implementation of such a proposal. We recommend specific changes to the PD in Appendix A.

D. The Scope of Monitoring Data Should Not Be Presumed to Suggest a Proper Window of Time for Transactions to Develop the RPS Adder

The PD proposes collection of data from a broad window of time to allow Staff to inform a modified benchmark.[8] It provides:

> Information on all fixed-price transactions (sales and purchases) for renewable energy executed in the past three years (n-3, n-2 and n-1) for delivery in the following three years (n, n+1, n+2) will help Staff monitor the impact of fixed-price transactions on the RPS Adder and propose a method to incorporate fixed-price contracts into the RPS Adder calculations.[9]

Gathering this information may be appropriate for "monitoring" whether it is advisable to shift to including long-term fixed-price contracts in the RPS Adder. However, using prices from such a wide window for a benchmark intended to reflect ***current*** RPS market prices would be contrary to D.18-10-019. Decision18-10-019 limits the relevant transactions for the Forecast RPS Adder to (at most) those executed two years prior to a single delivery year, consistent with its emphasis on "accurate' (read: recent) prices. We appreciate that the windows of time covered by the monitoring procedures are not intended to provide the windows for data to be employed in any modified benchmark.

III. ALL UNSOLD RPS ATTRIBUTES SHOULD BE VALUED AT THE RPS BENCHMARK TO RECOGNIZE THE VALUE OF THESE ATTRIBUTES TO BUNDLED CUSTOMERS AND CONFORM TO D.18-10-019

The PD concludes that "the value of unsold RPS resources should be zero" for purposes of the PCIA benchmark calculation.[10] It reasons that "[u]nsold RPS products also may well have

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8 *Id.,* Finding of Fact 7 at 46.

9 *Id.*

10 PD, Conclusion of Law 20 at 51.

no value if they expire or are banked by an LSE that is not able to use them for compliance."[11] It acknowledges, however, that the attributes may have value if "used by the IOU to exceed compliance requirements; retired to an IOU's RPS bank for hypothetical future use; or sold as lower value."[12]

The PD's conclusion is inconsistent with D.18-10-019. Decision18-10-019 says nothing about zero-value treatment for unsold RPS, in contrast to unsold RA. Reflecting D.18-10-019's silence on the matter, the Scoping Memo did not direct or mention resolution of this issue. Unsold RPS has yet to be shown to be a problem for any IOU. Moreover, the PD fails to recognize the clear and immediate value to IOUs of holding these attributes for their bundled customers as compliance insurance and carbon-free energy in the Power Content Label or Clean Net Short. The Commission should reject the PD's proposal and require the IOU to value unsold RPS attributes at the benchmark value. We expand on each of these arguments below.

First, nothing in D.18-10-019 provides for valuation of unsold RPS at zero. Decision 18-10-019 mentions unsold RA capacity eight times in its body text, and also contains an ordering paragraph addressing such capacity.[13] Not a single mention is made in D.18-10-019, however, of valuing "unsold RPS" at zero. Consistent with D.18-10-019, the February 1, 2019 Scoping Memo addresses unsold RA,[14] and makes absolutely no mention of treatment of unsold RPS. There is no procedural foundation basis for the Commission to adopt the PD's proposal to value unsold RPS at zero.

Beyond procedural concerns, the PD fails to account for the immediate value of unsold RPS to provide bundled customers. CalCCA pointed out in comments on the final Working Group 1 Report that unsold RPS "has value from the moment of generation," stating:

> Under existing rules, the IOU takes credit for the RPS attributes in the Power Content Label in the year generated, not in some future year. Similarly, RPS attributes provide value under the Clean Net Short proposal in the year of generation. Finally, unsold and

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[11] PD, Finding of Fact 19 at 47.

[12] PD, Finding of Fact 18 at 47.

[13] D.18-10-019 at 25, 71, 73, 80, 121, 149, 153-54 (Finding of Fact 4), and 160 (Ordering Paragraph 1.c).

[14] *Phase 2 Scoping Memo and Ruling of Assigned Commissioner* (Scoping Memo) at 4, Issue 7 ("D.18-10-019 specified that 'a zero or *de minimis* price shall be assigned for [RA] capacity expected to remain unsold for purposes of calculating the MPB.' Are further parameters needed to define a de minimis price, and if so, what are these parameters?").

> retained RPS can be used for bundled customers' compliance obligations in later years.[15]

Moreover, the unsold RPS provides a "buffer" for compliance insurance in the future, should changes in load or the RPS market occur. Indeed, PG&E acknowledged its intent to apply its retained RECs "toward meeting PG&E's bundled customer RPS obligations."[16] The PD errs in failing to account for these values.

Finally, the PD raises the concern that "valuing all retained or unsold RECs at this time might be perceived as prejudging the ultimate outcome of Working Group Three's proposal on portfolio optimization."[17] Declaring a value of "zero" is just as likely to be prejudicial, only in the other direction.

For all of these reasons, the Commission should reject the PD's adoption here of a zero value for unsold RPS in the benchmark calculation. To the extent that Working Group 3 is taking this issue up, all the more reason to not address it now.

IV. ALL UNSOLD RA ATTRIBUTES SHOULD BE VALUED AT THE PRICE FLOOR, IF ANY, SET BY THE IOU IN ITS SALES PROCESS FOR SUCH ATTRIBUTES TO THE EXTENT THE PRICE FLOOR EXCEEDS THE AMOUNT REQUIRED TO AVOID PENALTIES

In D.18-10-019, the Commission directed the IOUs to assign a "zero or de minimis price" to unsold RA capacity.[18] The Scoping Memo likewise directed parties to identify parameters for a "de minimis" price.[19]

The co-leads were unable to reach agreement on what "*de minimis*" means. CalCCA starts from the standpoint that it must mean *something*, and that to reduce it to a dollar value is best tethered to some objectively established amount. Accordingly, CalCCA proposes to use the sales "price floor" that IOUs set as, essentially, a reserve price below which they will not sell, to set the minimum (and so *de minimis*) as the value of the unsold RA. The Joint IOUs would read *de minimis* out of D.18-10-019, and simply value all unsold RA at zero. The PD erroneously adopts the Joint IOUs' approach.

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15 Comments of *California Community Choice Association on WNR Group One Draft End to End Benchmark and True-Up Proposal*, (CalCCA Comments) at 6.

16 PG&E Response to Join-CCA_004-QB, attached as Appendix B.

17 PD at 35.

18 D.18-10-019, Ordering Paragraph 1.c. at 159-160.

19 Scoping Memo, Issue 7, at 4.

The PD states that *de minimis* means close to zero, [20] and CalCCA agrees that *de minimis* means a small amount. That said, there must also be some rationale or "parameter" around the purpose of the value. For this reason, CalCCA proposed to rely on any value established by the IOU as a price floor in the sale of RA attributes. The price floor is the non-zero price at which the IOU deems it more reasonable not to sell the attribute than to sell it. Consequently, as CalCCA observed in its comments on the Working Group 1 Report, "[t]he use of a price floor implicitly acknowledges a value for the attribute." [21] As the PD notes, CalCCA's view was supported by the Alliance for Retail Energy Marketing, the Direct Access Customer Coalition, and the City of San Diego.

The PD concludes that to use the price floor would "provide a disincentive for the use of a price floor in an IOU solicitation,"[22] basing the analysis on the need to avoid Resource Adequacy Incentive Mechanism (RAAIM) charges. Even if the Commission agrees with the PD's assessment on RAAIM penalties, that does not mean that all price floors should be disregarded. To the extent that the IOU chooses a price floor that goes beyond mere penalty avoidance, its reasoning must be that retention has value above and beyond the value of any proposed sale.

For these reasons, CalCCA proposes that, at a minimum, the Commission direct that any price floor set above the level required for RAAIM penalty avoidance will be deemed the *de minimis* value of the attribute. Any other approach could allow the IOU to set unreasonable floor prices, allowing a cost shift from bundled to departing load customers by reducing the RA benchmark.

V. THE COMMISSION SHOULD DIRECT IOUS TO SELL EXCESS BY THE END OF AUGUST PRIOR TO THE DELIVERY YEAR

In addition to disagreeing over the appropriate price for unsold RAs, as discussed in Section IV, the co-leads differ on the conditions under which RA capacity may be deemed "unsold" and valued at a zero or *de minimis* price. The PD's resolution of this difference unreasonably gives bundled customers first call on the IOU's RA capacity and fails to appreciate the signals it would send to IOUs, who hold the lion's share of RA capacity in the market.

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20 PD at 40.
21 CalCCA Comments at 5.
22 PD at 42.

Moreover, the PD is internally inconsistent, failing to craft a solution that reflects its justification for adopting the IOUs' position. CalCCA thus requests that the Commission modify the PD to permit RA capacity to be deemed "unsold" and valued at zero or a *de minimis* price in the PCIA calculation only if the IOU has *timely* offered the RA to other LSEs to enable their compliance.

It is important to start with a clear understanding of what is at stake in this debate. The failure to provide requirements regarding the timing of an IOU's RA capacity sales creates a perverse incentive. An IOU has every incentive to hold back RA capacity from the market – from other LSEs whose customers pay for the capacity – as long as possible to mitigate any risk of its potential noncompliance. If all unsold capacity, regardless of when the capacity is offered for sale, is valued at zero or a *de minimis* price, it increases the PCIA charge paid by its competitors' customers. In other words, the IOU has no incentive to timely offer the capacity to the market, further squeezing an already tight RA market. Other LSEs consequently face a triple-whammy: they face higher RA costs in the RA market due to the resultant supply constraint, pay a higher PCIA due to the zero value of unsold amounts, and may incur noncompliance penalties because unsold RA was not offered in time for other LSEs to buy it for compliance purposes. This cannot be the right outcome.

CalCCA proposed in its comments on the Working Group 1 final report that RA capacity be considered "unsold" only if the RA is offered to the market "by the end of August preceding the compliance deadline for the relevant year, but not sold."[23] PG&E, not surprisingly, urged more liberal boundaries for RA capacity sales, contending that any RA offered for sale in a solicitation process — regardless of timing — but not sold should be valued at zero.[24] The PD punts the issue to Working Group 3 but, on an interim basis, sides with PG&E.[25] The PD accepts PG&E's argument that "[b]ecause final RA allocations are not determined until September, having the IOUs sell off RA resources prior to the September date could put bundled customers at financial risk, should the forecast change."[26]

The PD errs in two important respects. First, the PD grants bundled customers "first dibs" on all RA products in the portfolio. It provides that only when the needs of the utility's bundled customers are satisfied should other customers — customers who are bound to pay for

23 PD at 37.
24 PD at 37.
25 PD at 40-41.
26 *Id.*

the RA capacity — have access. This approach unreasonably discriminates against departing load customers. In protecting bundled customers from financial consequences for shortfalls in their RA procurement, it shifts the financial risk to departing load customers and their suppliers by contributing to a tightening market, encouraging other generators to increase RA prices to CCAs who must buy sufficient RA to meet compliance obligations, and passing unsold RA costs onto CCA customers through PCIA costs. Second, even if the PD's "bundled customers first" philosophy could be rationalized, the PD fails to act on its own observations. The PD implicitly acknowledges that the needs of the bundled IOU customers are known with certainty when the IOU's final RA requirement is received. Yet nothing in the PD requires the IOUs to immediately offer any excess to the market after receiving that requirement.

Pending resolution and without prejudice to the issue and Working Group 3, the Commission should clarify the PD to more fairly balance its impacts on departing load customers. The Commission has a continuum of options before it to do that. In CalCCA's ideal world, IOUs would be required to offer excess RA to the market early in the year, in a Spring solicitation, for that RA to qualify for "*zero or de minimis*" valuation. This approach would properly recognize that all LSEs bear risk as their forecasts and requirements change. Nonetheless, to create an alternative, CalCCA was willing to move the requirement in its proposal to the end of August, to allow for greater IOU certainty. By the end of August, the IOU will have received its initial forecast requirement from the Commission and will have updated load forecasts to account for load migration. Consequently, by the end of August, the IOUs should face little risk of offering RA capacity to the market; indeed their risk at the point should not be any more or less than any other LSE required to balance their position following receipt of final requirements. At the very least, however, the PD's recognition that the utility risk is eliminated once it receives its final allocation compels a requirement that the utilities offer excess RA for sale within five business days following receipt of their final RA requirements. Any resources not offered for sale at that time, which are not ultimately sold, may not be deemed "unsold" resources for benchmark purposes and will be deemed "sold" to bundled customers at the benchmark price.

VI. THE COMMISSION SHOULD MODIFY THE PD TO CONFORM TO THE CO-LEAD'S PROPOSAL REGARDING VALUATION OF RETAINED RA

The PD provides that RA that is "retained for IOU use" will be valued at the applicable benchmark, whether Forecast or Final.[27] While this conclusion mirrors the language presented in Tables 1a and 1b of the WG 1 Report, the PD misses the definition provided by the co-leads for RA "retained for IOU use." Co-leads define this term as "the amount of RA not offered for sale or forecasted to be offered for sale."[28] The Commission should modify the PD to include this critical definition and avoid potential disputes in ERRA proceedings.

VII. THE COMMISSION SHOULD CLARIFY FORECASTING AND TRUE-UP MECHANICS IN ADVANCE OF ERRA FILINGS

The co-leads reached consensus on the general methodology for forecasting unsold RA and for truing up fourth quarter (Q4) forecasts to actuals for the purposes of Energy Resource Recovery Account (ERRA) proceedings. However, although implicit in the Commission's findings, the Proposed Decision does not detail these associated true-up mechanics in two important respects.

First, the PD does not reflect the co-leads' agreement regarding the quantity of unsold RA that may be forecast in a Forecast ERRA proceeding. The co-leads agreed that if the forecasted volume "is equal to the prior year's unsold RA capacity plus or minus a value corresponding to forecasted change in departing load, then the volume will be accepted in the ERRA forecast without further review." Any other result will be subject to review for reasonableness.[29] Expressly adopting this recommendation will bring more discipline to the forecasting of unsold RA and ease the time required in the ERRA proceeding to address this issue.

Second, the Proposed Decision does not specify how a "true up" of forecast Q4 Portfolio Allocation Balancing Account (PABA) balances to actuals will be accomplished. When the true up for year n to the prior year's forecast occurs in Q4 of year n, final PABA balances will not be

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[27] PD, Appendix B, at 2.

[28] WG 1 Report, Table 1a, note 1 at 7.

[29] Pacific Gas and Electric Company (U 39-E) and California Community Choice Association Working Group One Report on Brown Power, RPS and RA True-Up (Issues 1 Through 7), May 31, 2019, at 8-9.

available. The true-up and any forecast ERRA value will thus be based on a forecast of year n Q4 costs and revenues. Consequently, the Q4 estimate used in the true up must itself be subject to true-up in year n+1 for accuracy. The Commission should amend the Proposed Decision to make this assumption explicit. Specifically:

> Forecasted Q4 costs and revenues for a particular year (n) used in the true-up for that year should be trued-up to actual Q4 costs in year n+1, with those updated costs reflected in the ERRA forecast for year n+2.

Proposed findings and conclusions are provided in Appendix A.

VIII. CONCLUSION

For the reasons specified above, CalCCA respectfully requests that the Commission adopt the changes to the Proposed Decision specified herein.

Respectfully submitted,

Evelyn Kahl
Counsel to the
California Community Choice Association

September 26, 2019

APPENDIX A

Proposed Findings of Fact, Conclusions of Law and Ordering Paragraphs

Findings of Fact:

6. ~~Incorporating fixed~~ Fixed-price bundled transactions should be included in~~to~~ RPS Adder calculations to the extent feasible and provided that incorporating these values does not materially sacrifice the accuracy of the benchmark.~~is expected to produce more accurate results and is ultimately the proper approach.~~

7. Information on all fixed-price transactions (sales and purchases) for renewable energy executed in the past three years (n-3, n-2 and n-1) for delivery in the following three years (n, n+1, n+2) will help Staff monitor the impact of fixed-price transactions on the RPS Adder, but relying upon this broad scope of transactions for the benchmark calculation would undermine the objective of reflecting current market values ~~and propose a method to incorporate fixed-price contracts into the RPS Adder calculations~~.

19. Unsold RPS products ~~also may well have no value if they expire or are banked by an LSE that is not able to use them for compliance~~ have immediate value to the IOU and its bundled customers by insuring against noncompliance and providing greater carbon-free energy for purposes of the Clean Net Short and the Power Content Label.

21. ~~RECs have value to the IOUs when they use the RECs. It is not clear under what circumstances costs may~~ Because unsold RPS products create immediate value for the utility and its bundled customers, failing to include those products at the RPS benchmark shifts costs from ~~between~~ bundled ~~and~~ to unbundled customers ~~when IOUs hold, do not sell, and do not use RECs~~.

~~22. If the IOUs use RECs in the future based on approved procurement plans,~~

~~the value in the year of generation may be different from the value at the time of the future transaction. To value all RECs in the year of generation could conflict with Commission-approved plans.~~

23. Failing to value unsold RECs in the PCIA benchmark calculation would prejudice the outcome of Working Group 3.~~Valuing all retained/unsold RECs might be seen to presuppose or conflict with the ultimate outcome on portfolio optimization, and possibly render that result moot as to the unused RECs that already have been valued and included in a PCIA calculation~~.

26. The co-chairs focused on zero and the floor price, and CalCCA identified as the parameter for determining a de minimis price the implicit value of the RA product revealed in any increment of the price floor above any amount required to avoid penalties. ~~but not on the parameters that will help define a de minimis price.~~

~~27. There are compelling arguments for why the floor price should not be designated as the "de minimis" price.~~

~~29. If the Commission were to assign the RA floor price value to unsold RA, this might imply that it is preferable for IOUs to sell their RA below the floor price and incur the penalties.~~

NEW FoF: For purposes of RA capacity valuation, "retained for IOU use" is defined as "the amount of RA not offered for sale or forecasted to be offered for sale."[30]

Conclusions of Law:

4. Energy Division should monitor the impact of fixed-price transactions and propose a method to include fixed-price contracts in calculating the RPS Adder by the end of 2020, to the extent such a method is feasible and does not undermine the accuracy of the benchmark. The

[30] WG 1 Report, Table 1a, note 1 at 7.

Energy Division Director shall ~~should be authorized to~~ hold workshops or utilize the existing Working Group process to develop the proposal.

20. ~~The value of unsold~~ Unsold RPS resources should be valued at the RPS benchmark. ~~zero.~~

22. The price for unsold RA should be set at the price floor set by the IOU in its sales of excess RA products, to the extent such floor exceeds the amount required to mitigate RAAIM penalties. ~~Because the floor price set in a solicitation is not necessarily a de minimis price and no party provided compelling arguments to set the floor price as the "de minimis" value for the unsold RA products, the Commission should adopt PG&E's proposal to set a zero value for unsold RA resources.~~

Ordering Paragraphs:

3.b. The value of unsold RPS products shall be ~~zero.~~set at the RPS benchmark.

3.e. ~~The value of unsold RA products shall be zero.~~ The price for unsold RA should be set at the price floor set by the IOU in its sales of excess RA products, to the extent such floor exceeds the amount required to mitigate RAAIM penalties.

New OP: The IOUs shall offer all excess RA capacity to the market not later than the end of August prior to the compliance deadline.

NEW OP: The IOU can forecast any volume of unsold RA. If the forecasted volume is equal to the prior year's unsold RA capacity plus or minus a value corresponding to forecasted change in departing load, then the volume will be accepted in the ERRA forecast without further review. The calculation of the amount corresponding to the change in departing load is the product of the year-over-year difference in IOU load share and the system RA requirement for each month. Volumes outside of range may be subject to reasonableness review in the ERRA Forecast proceeding.

NEW OP: Forecasted Q4 costs and revenues for a particular year (n) used in the true-up for that year should be trued-up to actual Q4 costs in year n+1, with those updated costs reflected in the ERRA forecast for year n+2.

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APPENDIX B

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2020 Forecast
Application 19-06-001
Data Response

PG&E Data Request No.:	Joint-CCA_004-Q13		
PG&E File Name:	ERRA-2020-PGE-Forecast_DR_Joint-CCA_004-Q13		
Request Date:	August 13, 2019	Requester DR No.:	004
Date Sent:	August 27, 2019	Requesting Party:	East Bay Community Energy/Marin Clean Energy/Peninsula Clean Energy/Pioneer Community Energy/San Jose Clean Energy/Silicon Valley Clean Energy/Sonoma Clean Power/Valley Clean Energy Alliance
PG&E Witness:	Marcus Keller	Requester:	Tim Lindl

QUESTION 13

Referring to the Chapters 9 Confidential Workpapers:

(a) Are all of the RECs in the WREGIS used by bundled customers to comply with the PG&E's RPS obligations?

(b) Are any of those RECs allocated to other LSEs in any manner other than direct sales?

ANSWER 13

PG&E objects to this question as it is not relevant to this proceeding and should be raised in either the RPS Plan or RPS Compliance proceedings. With that, please see the following responses.

a) RECs that are ultimately retained in PG&E's WREGIS account are expected to be used towards meeting PG&E's bundled customer RPS obligations.

b) Outside of RPS sales, RECs have not been allocated to other LSEs.

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 REPLY COMMENTS ON PROPOSED DECISION ON WORKING GROUP 1 ISSUES 1-7 AND 11

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October 1, 2019

TABLE OF CONTENTS

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 REPLY COMMENTS ON PROPOSED DECISION ON WORKING GROUP 1 ISSUES 1-7 AND 11

Pursuant to Rule 14.3 of the Commission's Rules of Practice and Procedure, the California Community Choice Association (CalCCA)[1] submits the following reply comments on the proposed *Decision Refining the Method to Develop and True Up Market Price Benchmarks*, issued on September 6, 2019 (Proposed Decision or PD). CalCCA's reply comments respond to the opening comments of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company (Joint IOUs)[2] and The Utility Reform Network (TURN).[3]

I. INTRODUCTION

CalCCA responds to the opening comments of the Joint IOUs and TURN, reaching the following conclusions:

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[1] California Community Choice Association represents the interests of 19 community choice electricity providers in California: Apple Valley Choice Energy, Clean Power SF, Clean Power Alliance, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Monterey Bay Community Power, Peninsula Clean Energy, Pioneer Community Energy, Pico Rivera Innovative Municipal Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Jacinto Power, San Jose Clean Energy, Silicon Valley Clean Energy, Solana Energy Alliance, Sonoma Clean Power, and Valley Clean Energy.

[2] *Opening Comments of Pacific Gas and Electric Company (U 39-E), Southern California Edison Company U 338 E), and San Diego Gas & Electric Company (U 902 E) on Proposed Decision Refining the Method to Develop and True Up Market Price Benchmarks*, Sept. 26, 2019 (Joint IOU Comments).

[3] *Opening Comments of the Utility Reform Network on the Proposed Decision of ALJ Atamturk Refining the Method to Develop and True Up Market Price Benchmarks*, Sept. 26, 2019 (TURN Comments).

- The Commission should consider revising the calculation of the RPS Adder *only if* it first determines that the benefits of revision outweigh the challenges and uncertainty of implementing such a change. Moreover, any such effort should be deferred, requiring an Energy Division Staff proposal by the end of 2020 to preserve scarce Staff and stakeholder resources.

- The Commission should defer to a more suitable proceeding the question of whether community choice aggregator (CCA) contract data should be provided to non-market participants; the Commission must first address whether adopting this practice would result in a CCA's inability to protect these contracts from disclosure to market participants under the Public Records Act.

Proposed Findings of Fact, Conclusions of Law and Ordering Paragraphs are provided in Appendix A.

II. THE COMMISSION SHOULD CONSIDER REVISING THE CALCULATION OF THE RPS ADDER *ONLY IF* IT FIRST DETERMINES THAT THE BENEFITS OF REVISION OUTWEIGH THE CHALLENGES OF IMPLEMENTING SUCH A CHANGE

The Proposed Decision adopts the co-leads' proposal for calculating the RPS Adder based on four quarters of Portfolio Content Category 1 index-plus contracts.[4] However, the PD appears to commit the Energy Division Staff to revising this methodology to incorporate long-term fixed-price transactions into the RPS Adder, to take effect in 2021.[5]

CalCCA agrees with the Joint IOUs that the Proposed Decision lacks support for its conclusion that "[i]ncorporating fixed-price bundled transactions into RPS Adder calculations is expected to produce more accurate results and is ultimately the proper approach."[6] As discussed in CalCCA's Comments, the challenges of implementing such an approach (which CalCCA explained in detail) outweighed the value of any asserted potential increased accuracy.[7] CalCCA

[4] PD, Ordering Paragraph 3(b) at 52.

[5] PD, Ordering Paragraph 3(c) at 53. *See California Community Choice Association Reply Comments on Proposed Decision on Working Group 1 Issues 1-7 and* 11, Sept. 26, 2019 (CalCCA Comments) at 2-3.

[6] PD, Finding of Fact 6, at 46. *See* Joint IOU Comments at 6.

[7] CalCCA Comments at 3-4.

explained these challenges in detail.[8] TURN, while continuing to suggest developing a method for incorporating these transactions by the end of 2020, provides nothing more in terms of guidance.[9]

For all of the reasons stated in CalCCA's and the Joint IOUs' opening comments, incorporating long-term, fixed-price bundled RPS contracts will not increase the RA Adder's accuracy due to the many assumptions that will be required to integrate the prices into the benchmark. It thus is unnecessary to commit Energy Division and stakeholders to this exercise on an expedited timeline when so many other issues – including Working Group 3, resource adequacy and integrated resource planning issues – are pressing and are likely to deliver higher value.

The Commission has been in the business of administrative price-setting for decades, with commensurate experience in how controversial and time-consuming such exercises are. Think back on the qualifying facility avoided-cost price proceedings, the development of the "market price referent" for RPS procurement and, the recent history of the Power Charge Indifference Adjustment. The Commission is well aware of the time required to chase down all of the methodological rabbit holes and the often marginal value of that chase. CalCCA thus requests that the Commission modify the PD to not set a particular time within which Energy Division must revise the RPS Adder calculation. By all means require a *proposal* by the end of 2020, rather than *implementation*, to avoid further burdening already scarce Energy Division and stakeholder resources.

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8 CalCCA Comments at 4.
9 TURN Comments at 1.

III. DECISIONS REGARDING CONFIDENTIALITY ARE OUTSIDE THE SCOPE OF THIS WORKING GROUP.

TURN offers comments on the PD's proposal to permit non-market participants access to data provided to Staff for benchmarking purposes.[10] TURN contends that "requiring the development of a single NDA that can be executed by NMPs to gain access to all the relevant confidential data collected by the Energy Division for the development of PCIA forecasts and true-ups."[11]

CalCCA requests that the Commission defer this issue to a more appropriate forum. The Scoping Memo for this Phase did not identify data access or confidentiality as issues within scope of any working group. Moreover, the question of provision of contract data is a sensitive issue to community choice aggregators (CCAs), who are governmental entities. While the ability of a CCA to protect its electricity contracts from public disclosure is relatively clear when the recipient is the Commission and its Staff, there is no similar exception from disclosure for a contract provided to another entity that is not a state agency. CalCCA thus requests that the Commission defer this question to a more suitable forum in which it can be fully examined for purposes that may extend beyond Working Group 1.

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10 PD, Conclusion of Law 18, at 51. *See* TURN Comments at 3-4.

11 TURN Comments at 3.

IV. CONCLUSION

For all of the foregoing reasons, CalCCA requests that the Commission adopt the proposed modifications detailed in CalCCA's opening comments and the revised findings of fact and conclusions of law specified in Appendix A to these reply comments.

October 1, 2019

Respectfully submitted,

Evelyn Kahl
Counsel to the
CALIFORNIA COMMUNITY CHOICE
ASSOCIATION

APPENDIX A

Proposed Findings of Fact, Conclusions of Law and Ordering Paragraphs

Findings of Fact:

~~6. Incorporating fixed-price bundled transactions into RPS Adder calculations is expected to produce more accurate results and is ultimately the proper approach.~~

~~15. A standardized non-disclosure agreement is reasonable for efficient and equal access for nonmarket participants to all confidential information.~~

Conclusions of Law:

4. Energy Division should monitor the impact of fixed-price transactions and propose, by the end of 2020, a method to include fixed-price contracts in calculating the RPS Adder, but only if there is evidence demonstrating that such a method is feasible and likely to produce greater accuracy, ~~by the end of 2020~~. The Energy Division Director should be authorized to hold workshops or utilize the existing Working Group process to develop the proposal.

~~18. The Commission should adopt TURN's proposal to give NMPs access to confidential data.~~

Ordering Paragraphs:

1.c. All Load Serving Entities shall provide Staff with information on all fixed-price transactions (sales and purchases) for renewable energy executed in the past three years (n-3, n-2 and n-1) for delivery in the following three years (n, n+1, n+2). Energy Division shall monitor the impact of fixed-price transactions and propose, by the end of 2020, a method to include fixed-price contracts in calculating the RPS Adder, but only if there is evidence demonstrating that such a method is feasible and likely to produce greater accuracy ~~by the end of 2020~~. We authorize the Energy Division Director to hold workshops or utilize the existing Working Group process to develop the 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 Annual Local and Flexible Procurement Obligations for the 2019 and 2020 Compliance Years.	R.17-09-020 (Filed September 28, 2017)

COMMENTS OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON INFORMAL WORKSHOP REPORTS

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August 2, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2019 and 2020 Compliance Years.	R.17-09-020 (Filed September 28, 2017)

COMMENTS OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON INFORMAL WORKSHOP REPORTS

Decision 19-02-022 (Track 2 Decision) requires participants to "undertake a minimum of three workshops over the next six months to identify workable CPE and central procurement structure proposals."[1] Pursuant to Ordering Paragraph 7 of the Track 2 Decision, each of the facilitators of the workshops (the Joint IOUs, Shell Energy, and CalCCA) filed informal reports on their respective workshops on July 17, 2019.

By email dated July 22, 2019 Administrative Law Judge Chiv provided all parties with the opportunity to file comments on these reports. The California Community Choice Association (CalCCA) timely files these comments on the informal workshop reports.

I. INTRODUCTION

Workshop #1 and #2 addressed whether a proposed central procurement entity would follow either a "full procurement" or "residual" model. Workshop #3 and #4 were to consider issues surrounding the concept of a central procurement entity. Workshops #5 and #6 considered

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1 D.19-02-022, Ordering Paragraph 3, at 45.

implementation and other issues related to the proposal. Workshops #6 and #7 were to be a wrap-up and proposal based on consensus reached.

CalCCA commends all of the parties who participated in the workshop process to discuss these complex issues. Although many parties spent considerable time and effort participating in these workshops, however, little consensus was reached. Many proposals were put up for consideration and many challenges were discussed, but a consensus proposal did not emerge.

CalCCA reviewed the comments and reports filed, and in response has developed a proposal based on the information gleaned from the workshop process. CalCCA submits the following proposal for the establishment and operation of a central procurement entity, taking into account each of the topics addressed in the workshops.

II. PROPOSAL

A. Identity of the CPE - (Workshops #3 and #4)

CalCCA has reviewed and considered the jurisdictional issues, governance issues and structure anticipated for a central procurement entity (CPE). CalCCA proposes that the CPE be established to procure on behalf of all LSEs otherwise subject to Section 380. CalCCA recommends the establishment of a new state entity, or an expansion of the role of any existing state entity, to serve as CPE.

A state entity will be preferable to either an IOU or a for-profit entity in this role. A state entity will provide the cleanest approach from a jurisdictional standpoint. Unlike an IOU or a for-profit entity, a state entity has a categorical exemption from the Federal Power Act.[2]

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[2] Section 201(f) of the FPA provides an explicit exemption from Part I of the Act to "a State or any political subdivision of a State…or any agency, authority, or instrumentality…or any corporation which is wholly owned, directly or indirectly, by any one….of the foregoing, unless such provision makes specific reference thereto." 16 U.S.C. § 824(f). The Court of Appeal for the Ninth Circuit concluded this

Moreover, a state entity structure will ensure competitive neutrality in both wholesale and retail electric markets. Putting an IOU in the role of CPE presents an unfair opportunity for self-dealing and an inherent conflict between a market participant's duty to its shareholders and the CPE's competitive neutrality, transparency and independence. It is questionable whether these problems can be overcome entirely through the imposition of self-implemented IOU protocols and other affiliate rules. Structural separation of the CPE from any one market competitor eliminates these inherent risks.

B. Procurement Model - (Workshops #1 and #2)

CalCCA proposes adoption of a residual procurement model. The CPE will procure resource adequacy (RA) products on a multi-year basis in the service territories of the investor-owned utilities (IOUs), beginning in 2021 for the 2022 Resource Adequacy year. As a result of the CPE's primary responsibility, the existing LSE compliance obligation will shift from individual LSEs to the CPE, although individual LSEs will be entitled to procure on their own behalf.

1. Mechanics of CPE Procurement

CalCCA proposes that the CPE work with the CAISO and the Commission to identify the pool of eligible effective resources, taking into account RFO offer prices, the effectiveness of resources in addressing local area constraints, state energy objectives, resource performance characteristics, and other selection criteria using a methodology developed by the Commission through a public process.

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provision creates a blanket exemption for these "State Entities" from FERC jurisdiction under sections 205 and 206 of the FPA. *Bonneville Power Admin. v. FERC,* 422 F.3d 908 (9th Cir. 2005).

The products procured by the CPE will be subject to California Independent System Operator (CAISO) must offer obligations. The CPE will not procure dispatch rights or impose requirements beyond CAISO must-offer obligations on the energy market participation of procured capacity.

The CPE will meet its compliance requirement by contracting for resources for a period not to exceed three years. The CPE will purchase RA only products, on an annual basis. The CPE will contract on a rolling three-year basis, ensuring that the aggregate of (a) RA self-procurement by LSEs plus (b) the CPE's procurement of the remainder of the Collective Requirement, total RA Requirement as shown in Table 1.

Table 1:
Percentage of Collective RA Requirements
Procured on a Multi-Year Basis

	Year 1	Year 2	Year 3
System RA	100%	75%	50%
Local RA	100%	100%	75%
Flex RA	100%	75%	50%

2. CPE Showing of Self-Procurement

Each LSE will continue to receive the CEC's individualized forecast of its load share and may show Local, System and Flexible resources to the CPE on an annual basis. The CPE will show its procured resources, by month, on a year ahead basis, to the CPUC and CAISO sufficient to demonstrate that the amount procured by the CPE and capacity self-procured by LSEs in aggregate meet the collective requirements. There will be no month-ahead showings required.

Following the CPE's showing, the CAISO will identify any resource deficiency for the upcoming year for System and Flexible RA products and two years forward for Local RA products. The CPE will then bilaterally negotiate additional procurement to eliminate the deficiency prior to the CAISO conducting backstop procurement. To the extent any deficiency still exists following CPE procurement, the CAISO will continue its backstop procurement role in according with its then-applicable tariff.

3. Cost Responsibility and Allocation

CalCCA proposes that the CPE calculate each LSE's respective cost allocation, and recover its costs from the LSEs through a Resource Adequacy Charge. Each LSE will bear Cost Responsibility for its share of the RA procured by the CPE on its behalf, which will be determined on an ex post facto basis. Cost allocation must leave the CPE revenue neutral.

The CPE, in coordination with the Commission, will determine on an ex post facto basis each LSE's share of the collective requirement on a monthly basis.

The LSE will allocate its total CPE cost to its customers as a part of the generation rate identified by the LSE and recovered by the IOU through a customer's monthly bill. The LSE will be responsible for balancing resulting over/under-collections throughout the year and adjust generation rates as necessary. LSEs' payment to the CPE will be secured by agreements between the LSE and the CPE, based on creditworthiness and collateral protocols to be developed by the CPE. Each LSE agreement will include a provision that, in the event of default by an individual LSE, CPE revenue neutrality shall be maintained through appropriate cost recovery from remaining LSEs.

C. Other Issues (Workshops $5 and #6)

1. Transparency

CalCCA proposes that the CPE publicly report in detail all formation and annual administrative costs. CalCCA also proposes that CPE solicitations be publicly noticed and available. CalCCA proposes the CPE confidentially report to the CPUC the specific prices of its solicitations to the CPUC, and the Commission report publicly the average price for all products and months procured, aggregating in local RA areas or subareas where the capacity procured from fewer than three sellers to prevent disclosure of individual resource price information. The CPE will report the monthly volume of procurement by product and local area and publish actual volumes annually on an ex post facto basis.

2. Program Review

CalCCA proposes the Commission, in coordination with the CAISO and CEC, review the continuing need for the CPE not later than January 1, 2027.

Dated: August 2, 2019

Respectfully submitted,

/s/ Evelyn Kahl

Evelyn Kahl

BUCHALTER, A PROFESSIONAL CORPORATION
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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 Annual Local and Flexible Procurement Obligations for the 2019 and 2020 Compliance Years	R.17-09-020

JOINT REPLY COMMENTS OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION, CALPINE CORPORATION, INDEPENDENT ENERGY PRODUCERS ASSOCIATION, MIDDLE RIVER POWER, LLC, NRG ENERGY, INC., SAN DIEGO GAS & ELECTRIC COMPANY (U 902-E), SHELL ENERGY NORTH AMERICA (US) L.P., AND WESTERN POWER TRADING FORUM ON MOTION FOR ADOPTION OF SETTLEMENT AGREEMENT

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October 15, 2019

Contents

Table of Contents continued

TABLE OF AUTHORITIES

Table of Contents continued

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2019 and 2020 Compliance Years	R.17-09-020

JOINT REPLY COMMENTS OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION, CALPINE CORPORATION, INDEPENDENT ENERGY PRODUCERS ASSOCIATION, MIDDLE RIVER POWER, LLC, NRG ENERGY, INC., SAN DIEGO GAS & ELECTRIC COMPANY (U 902-E), SHELL ENERGY NORTH AMERICA (US) L.P., AND WESTERN POWER TRADING FORUM ON MOTION FOR ADOPTION OF SETTLEMENT AGREEMENT

Pursuant to Rule 12.2 of the Commission's Rules of Practice and Procedure, the California Community Choice Association, Calpine Corporation, Independent Energy Producers Association, Middle River Power, LLC, NRG Energy, Inc., San Diego Gas & Electric Company, Shell Energy North America (US) L.P., and the Western Power Trading Forum (together, the "Settling Parties")[1] file these Joint Reply Comments on the *Joint Motion of [the Settling Parties] for Adoption of the Settlement Agreement for a "Residual" Central Procurement Entity Structure for Resource Adequacy* dated August 30, 2019 ("Joint Motion").

I. THE SETTLEMENT AGREEMENT IS A GOOD FAITH, COLLABORATIVE RESPONSE TO THE COMMISSION'S REQUEST FOR PARTIES TO PRESENT A WORKABLE CENTRAL BUYER PROPOSAL

The Commission has struggled for nearly two years to develop a resource adequacy ("RA") central procurement framework through stakeholder consensus. Unfortunately, those efforts were brought to a virtual standstill by a logjam of highly polarized views on how the

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1 Counsel to CalCCA is authorized to sign this Joint Motion on behalf of each of the Settling Parties.

framework should be structured and who should serve as the central procurement entity ("CPE"). While the Settlement Agreement does not attempt to fully resolve all issues, it breaks the logjam by providing the Commission a workable RA-CPE framework in *direct response to the Commission's unambiguous requests.*

The Commissioners challenged parties at the February 21, 2018, Business Meeting and expressly in Decision (D.) 19-02-022 to develop a workable, implementable solution for central procurement. The Commission stated that a "workable" implementation solution would address several known challenges to the local RA program:

(1) "costly out-of-market RA procurement due to local procurement deficiencies";

(2) "load migration and equitable allocation of costs to all customers";

(3) "cost effective and efficient coordinated procurement";

(4) "treatment of existing local RA contracts";

(5) "opportunity for and investment in procurement of local preferred resources"; and

(6) "retention of California's jurisdiction over procurement of preferred resources."[2]

The Commissioners further mentioned the need to mitigate both the risk of RA deficiencies and the need for waiver requests (which then-President Picker referred to as "RA crimes"). In addition, while not mentioned expressly, the Commission must ensure that any central buyer mechanism complies with its statutory obligation, including the requirement – repeated twice in Public Utilities Code Section 380[3] – to ensure self-procurement autonomy for Community Choice Aggregators. All this work, the Commission directed, needed to be completed within sufficient time to adopt a central procurement mechanism in the fourth quarter of 2019.[4]

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[2] D.19-02-022 at 18.
[3] Cal. Pub. Util. Code §§ 380(a)(5), 380(g)(5).
[4] D.19-02-022 at 18.

The Settlement Agreement responds directly and effectively to the Commission's call. It will:

(1) Reduce out-of-market RA procurement and eliminate local procurement deficiencies by placing the RA Central Procurement Entity ("RA-CPE") in a backstop role;

(2) Address load migration through the use of a cost allocation mechanism based on a load-serving entity's ("LSE's") actual load and grounded in principles of cost causation;

(3) Result in cost effective and efficient coordinated procurement, by placing the RA-CPE in a position to ensure all RA requirements are met;

(4) Preserve the value of existing RA procurement commitments and RAcontracts ;

(5) Preserve the opportunity for and investment in procurement of local preferred resources," leaving room to further address this issue through development of selection criteria for RA-CPE procurement; and

(6) Retain California's jurisdiction over procurement of preferred resources by keeping as much responsibility for RA procurement in the hands of LSEs and allowing the Commission to determine RA-CPE resource selection criteria.

Critically, the Settlement Agreement also complies squarely with Section 380 by preserving LSE procurement autonomy.

The Settlement Agreement reflects major compromises and the resulting consensus proposal among Community Choice Aggregators ("CCAs"), one of the state's largest investor-owned utilities ("IOUs"), and key wholesale market participants, with the general support of the California Independent System Operator ("CAISO") and electric service providers ("ESPs"). Other than the proposed RA-CPE framework outlined in the Settlement Agreement, this proceeding has not produced any well-developed alternative proposals that are fully supported by more than a single party. The Settlement Agreement thus not only represents the only proposal made in direct response to the Commission's repeated requests for a consensus central buyer proposal, it also represents real progress.

Comments on the Settlement Agreement attempt to move the Commission back into the logjam:

- Pacific Gas and Electric Company ("PG&E") and Southern California Edison ("SCE") continue to promote their individually preferred procurement models.

- Other parties, even some that favor a residual procurement model, "oppose" the settlement for its failure to address their particular issues.

- Still other parties object to the Settlement Agreement because it does not address all the issues identified in the Track 2 Decision, in some cases ignoring the fact that the Settling Parties intentionally left issues open to allow for additional stakeholder input.[5]

A few parties also take issue with the Settlement Agreement on grounds that the Settling Parties do not "fairly represent all affected IOU or other LSE interests and do not include any parties representing customers or environmental interests,"[6] and not all parties were included in the settlement discussions.[7]

The Settling Parties acknowledge that not all parties were included in our settlement discussions,[8] that the Settlement Agreement could not in the time provided address all the interests of all stakeholders, and that it does not address all the implementation issues that will need to be addressed. The Settling Parties' limited scope and outreach to other parties, however, was a consequence of the clear lines of polarization in the Commission-directed workshop process and the very limited time available to develop a consensus proposal. Given the amount of work that was required to get just the Settling Parties on the same page, it is no exaggeration

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5 Comments of The Utility Reform Network (TURN Comments) at 1; Comments of the Center for Energy Efficiency and Renewable Technologies (CEERT Comments) at 2.

6 Comments of Southern California Edison (SCE Comments) at 18-19.

7 *See*, *e.g.*, Comments of the Cogeneration Association of California (CAC Comments) at 2.

8 The Settling Parties note that more parties participated in settlement discussions than ultimately became signatories and, further, that representatives from one or more of the Settling Parties had multiple discussions with several other important parties during the course of settlement discussions.

to say that, at the end of the day, there simply would have been no work product to timely present to the Commission had the settlement discussions been opened to more parties.

The Settlement Agreement thus represents a good faith and collaborative effort to respond to the Commission's requests with a detailed and workable proposal for a residual central procurement framework. The Settling Parties believe that the proposed RA-CPE framework is in the public interest[9] and request adoption of the Settlement Agreement in its entirety and without modification.

II. THE SETTLEMENT AGREEMENT IS WITHIN THE BROAD SCOPE OF THIS PROCEEDING AND RESPONDS TO RECENT FINDINGS IN R.16-02-007

SCE and PG&E claim that that Settlement Agreement exceeds the scope of Track 2 by proposing multi-year requirements for system and flexible RA.[10] PG&E further claims that the referral of the issue of IOUs' sales of their "excess" RA capacity to Working Group 3 in the Power Charge Indifference Amount ("PCIA") rulemaking, Rulemaking (R.) 17-06-026, likewise exceeds this proceeding's scope.[11] These objections are without merit and should be dismissed.

PG&E's concern regarding the Settlement Agreement's reference to IOU excess sales is misguided. The Settlement Agreement expressly acknowledges that the sale of IOUs' excess RA is being addressed in R.17-06-026, Working Group 3.[12] The Settlement Agreement does not propose to address or resolve the issue in this proceeding, and the Settlement Agreement's mere mention of the issue does not cause the Settlement Agreement to exceed the scope of this proceeding.[13]

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[9] Joint Motion at 7.
[10] SCE Comments at 4. Comments of Pacific Gas & Electric Company (PG&E Comments) at 7.
[11] PG&E Comments at 18.
[12] Joint Motion, Appendix A at 6, n.3.
[13] *Id*.

In contrast, PG&E's and SCE's suggestion that the Settlement Agreement goes beyond the scope of this proceeding by proposing multi-year forward procurement requirements for system and flexible RA warrants a more fulsome discussion. While the Settling Parties acknowledge the Commission did not adopt proposals for broader multi-year requirements in Track 2, the issue has been discussed repeatedly in this proceeding. More importantly, looming shortages of system RA capacity heighten the need for prompt consideration of the issue.[14]

The scope of this proceeding – R. 17-09-020 – is very broad. As the Commission's Order Instituting Rulemaking ("OIR") for the proceeding stated:

> We open this rulemaking to oversee the resource adequacy program, make any changes and refinements to the program, and establish local and flexible procurement obligations applicable to load-serving entities beginning with the 2019 compliance year.[15]

The 2018 Scoping Memo establishing the scope for Tracks 1 and 2 likewise left the door open to consider "RA program reforms necessary to maintain reliability while reducing potentially costly backstop procurement…."[16] These reforms, the Commission explained, "may include central buyers, a multi-year framework for Local RA (and associated cost allocation), as well as *other proposals to address out-of-market procurement and increase transparency*."[17] It also made clear that a multi-year local RA program was simply one example of such a proposal.[18]

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14 See Proposed *Decision Requiring Electric System Reliability Procurement for 2021-2023*, issued September 12, 2019 in R.16-02-007, recommending the extension of compliance deadlines for once-through-cooled generating units and directing the procurement of 2,500 MW of incremental capacity to address system RA capacity shortfalls.

15 *Ordering Instituting Rulemaking*, R.17-09-020, Oct. 4, 2017, at 1.

16 2018 Scoping Memo at 6, §4.b.

17 *Id.* at 6-7 (emphasis added).

18 *Id.* at 4 ("Potential approaches to reduce future out-of-market RA procurement, such as a multi-year Local RA program and/or one or more central buyers (e.g., the large investor-owned utilities), will be prioritized for consideration in Track 1 of this proceeding.").

In its Track 1 decision, D.18-06-030, the Commission observed that parties had focused on multi-year procurement for system and flexible requirements, including SDG&E, the Western Power Trading Forum, Middle River Power, the Independent Energy Producers Association, NRG and others.[19] The Commission concluded that it would not "adopt multi-year requirements for flexible and system RA in this proceeding *at this time*…."[20] It made clear, however, that "[g]oing forward, the Commission may consider an expansion of multi-year requirements to flexible and/or system RA."[21]

The Commission again observed in its Track 2 decision, D.19-02-022, that several parties presented proposals that supported "expanding multi-year and/or central procurement to system and flexible requirements...."[22] The Commission stated further that "the RA procurement issues observed thus far pertain to local RA and therefore, expansion to flexible and system RA is premature and needs to be fully explored."[23] Thus, while declining to adopt a broader multi-year RA program for the time being, the Commission concluded:

> [T]here may be potential benefits to expanding multi-year requirements to system and flexible RA, and [we] will continue to monitor and evaluate the multi-year local RA program to consider expansion to flexible and/or system RA in the future.[24]

In short, while the Commission has not yet adopted a multi-year system and/or flexible RA program, the contention that the inclusion of this feature in the Settlement Agreement "violates Rule 12.1(a) by addressing issues outside the scope of Track 2 of the proceeding"[25] ignores the substantial consideration the issue has had throughout the proceeding.

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19 D.18-06-030 at 26-27.
20 *Id.* at 28.
21 *Id.*
22 D.19-02-022 at 33.
23 *Id.*
24 *Id.* at 34.
25 *See*, *e.g.*, SCE Comments at 14-15; PG&E Comments at 7-9.

The Settling Parties respectfully submit that, despite the Commission's past reticence, the time has come to expand the multi-year local RA program to include system and flexible RA. The CAISO's comments echo this sentiment, focusing almost exclusively on the benefit of the Settlement Agreement's multi-year system and flexible RA requirements.[26] As the CAISO explains:

> Recent developments in this proceeding and the Commission's Integrated Resource Planning (IRP) proceeding demonstrate the need for system and flexible capacity forward procurement requirements. On September 12, 2019, the Commission issued a Proposed Decision highlighting potential system resource adequacy shortages beginning in 2021. The potential system shortages were not addressed by the current resource adequacy construct because it fails to consider system needs beyond the next year. The Settlement Agreement would provide a significant first step toward ensuring near-term needs by requiring system and flexible resource procurement obligations three-years forward.[27]

Indeed, in the context of the system RA shortage forecasted for 2021-2023 in the IRP proceeding, extending multi-year requirements to system and flexible RA could facilitate the retention of resources on the brink of contract expiration or retirement that do not have local RA value.

SCE contests these conclusions, arguing that "'locking in' system and flexible RA capacity three years forward …is problematic."[28] SCE seems to argue, based on very preliminary statements by the CAISO in R.16-02-007,[29] that the value for resources may change depending upon how requirements are measured in the future. The Settling Parties agree that the CAISO has introduced uncertainty regarding future system RA requirements, and the CAISO is

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26 CAISO Comments at 2-3.
27 *Id.*
28 SCE Comments at 21.
29 SCE comments at 21, referring to Reply Comments of the California Independent System Operator Corporation, R.16-02-007, August 12, 2019.

also engaged in an initiative to modify the flexible RA framework.[30] The Settlement Agreement, however, does not attempt to define how requirements will be set or what products will meet those requirements. Moreover, parties should reasonably expect that these issues will be addressed before the 2022 compliance year – the first delivery year for which the RA-CPE framework would be implemented. For these reasons, the Commission should reject the "scope" concerns cited by PG&E and SCE as misplaced.

III. THE SETTLEMENT AGREEMENT COMPORTS WITH STATE LAW AND MAINTAINS THE STATE'S CENTRAL ROLE IN ENSURING RELIABILITY

A. The Settlement Agreement is Consistent with the Statutory Authority Conferred to the Commission by Section 380

The Settlement Agreement provides expressly its intent to implement the RA-CPE framework under Public Utilities Code Section 380, which grants the Commission authority to oversee reliability through the state-administered resource adequacy program. The Settlement Agreement provides:

> The RA-CPE will implement a centralized resource adequacy mechanism under the authority delegated to the Commission pursuant to Public Utilities Code Section 380(i) or any subsequently enacted statute conferring such authority.[31]

More specifically, the Settlement Agreement implements the Commission's authority under Section 380(i), which authorizes the Commission to "consider a centralized resource adequacy mechanism among other options" in implementing its RA authority.[32] Finally, the Settlement Agreement maximizes the ability of CCAs to procure RA on behalf of their load, as required by §§ 380(a)(5) and (g)(5).

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30 *See Resource Adequacy Enhancements, Second Revised Straw Proposal,* at 57-58. http://www.caiso.com/Documents/SecondRevisedStrawProposal-ResourceAdequacyEnhancements.pdf
31 Joint Motion, Appendix A at 2.
32 Cal. Pub. Util. Code §380(i).

Several parties challenge this conclusion. The American Wind Energy Association of California ("AWEA-CA") and the Large-Scale Solar Association ("LSA") claim that it is unclear how the selection of the resources to meet the Collective Residual RA Requirements will comport with § 380.[33] The Joint DR Parties assert that the Settlement Agreement ignores provisions of § 380.[34] They claim that no provision of the Settlement Agreement ensures any mandated outcomes, and none of the mandatory requirements of § 380 are guaranteed by any provision of the Settlement Agreement or proposed RA-CPE framework.[35] These parties' concerns appear to focus on the provisions of § 380(b). [36]

Section 380(b) requires the Commission to "ensure the reliability of electrical service in California while advancing, to the extent possible, the state's goals for clean energy, reducing air pollution, and reducing emissions of greenhouse gases"[37] and to meet other specified objectives. AWEA-LSA focus their needs on the implementation of the "Loading Order" by the CPE.

The Joint DR Parties and AWEA-LSA identify no specific impediments that will prevent the RA program, as enhanced by the RA-CPE framework, from meeting the objectives stated in Section 380(b). They only assert that there has been no demonstration of whether and how the RA-CPE framework will meet these objectives or, in the case of the Joint DR Parties, that the Settlement Agreement will guarantee the objectives are met. As an initial matter, no framework can "guarantee" that the statutory objectives will be met. However, nothing in the Settlement Agreement would prevent the achievement of these objectives. The aforesaid parties' concerns

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33 Comments of the American Wind Energy Association of California and Large-Scale Solar Association (AWEA-LSA Comments) at p. 4.
34 Comments of Joint DR Parties (Joint DR Comments) at 3.
35 Id. at 8.
36 AWEA-LSA Comments at 5; Joint DR Comments at 8-9.
37 Cal. Pub. Util. Code §380(b).

are thus best be addressed through the RA-CPE resource selection criteria, which the Settlement Agreement reserves for further development through a public stakeholder process.[38]

B. The Settlement Agreement Does Not Delegate Commission Jurisdiction to the RA-CPE

Parties challenge the Settlement Agreement on grounds that the Settlement Agreement unlawfully delegates Commission jurisdiction to the RA-CPE and fails to provide sufficient Commission oversight. However, their positions appear to stem to a large degree from a misapplication of the law giving the Commission authority to establish "just and reasonable" rates. In addition, the answer to their concerns will depend on the identity of the entity ultimately selected to act as the RA-CPE. What is appropriate oversight for a state-agency RA-CPE may not be the same oversight required in the case of, for example, a third-party RA-CPE. For these reasons, their criticisms are not grounds for rejection of the Settlement Agreement.

Some parties suggest that the Settlement Agreement unlawfully delegates the Commission's authority to the RA-CPE.[39] SCE complains that "there is very little discussion of a Commission oversight process in the Settlement Agreement," noting that the provisions instead point to coordination of the RA-CPE activities with the Commission, the CAISO, and the California Energy Commission ("CEC").[40] PG&E asserts that the Settlement Agreement neglects to include oversight by the Commission over what is procured, asserting that "this lack of oversight would limit the state's ability to implement state policy goals and reduce stakeholder

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[38] Joint Motion, Appendix A, §III.C.2.c. at 3.

[39] Public Advocates Office states: "allowing the CPE to determine whether costs above the Soft Offer Cap are reasonable would be an unlawful delegation of the Commission's statutory obligation to determine that rates are just and reasonable." Comments of the Public Advocates Office (Public Advocates Office Comments) at 7.

[40] SCE Comments at 31.

involvement in procurement decisions."[41] The Public Advocates Office likewise argues that the Settlement Agreement "[f]ails to provide for sufficient oversight of the Central Procurement Entity (CPE) by the Commission."[42] The Public Advocates Office cites insufficient oversight of contract costs, formation and administrative costs, and creditworthiness and collateral protocols.[43]

These parties start from the premise that heavy-handed cost and rate regulation of the RA-CPE is required – a premise that warrants reconsideration through an examination of the Commission's authority under Sections 380 and 451. Section 451 confers the Commission authority to determine whether the rates and charges imposed by a *public utility* are just and reasonable.[44] Thus, unless the RA-CPE is deemed a public utility – a question that has not yet been broached – the Commission will, under current law, have no direct rate regulation authority over the RA-CPE. Moreover, nothing in § 380 extends the Commission's rate authority to the rates paid by customers of CCAs or ESPs.[45] Section 380, instead, confers on the Commission authority to ensure reliability. In other words, it is the Commission's business to ensure that LSEs obtain enough of the right types of capacity to ensure reliability; it is not within the Commission's purview to oversee the prices at which LSEs meet their obligations, with the exception of public utilities. Thus, the notion that the Commission should maintain authority to oversee and approve the costs, rates and charges of the RA-CPE requires more extensive consideration.

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41 PG&E Comments at 15.
42 Public Advocates Office Comments at 1.
43 *Id.* at 8.
44 Cal. Pub. Util. Code §451.
45 The Commission has no jurisdiction to regulate the rates that CCAs and ESPs charge their customers. For ESPs, this limitation on the Commission's jurisdiction is codified in Public Utilities Code §394(f), which in pertinent part provides: "Nothing in this part authorizes the commission to regulate the rates or terms and conditions of service offered by electric service providers."

In addition, the RA-CPE function is, to a large degree, self-regulating. It is up to local governments, in the case of CCAs, and sophisticated customers, in the case of ESPs, to evaluate the rates implemented by CCAs and ESPs to recover their allocated RA-CPE costs. If a CCA or an ESP, on behalf of its customers, believes that RA-CPE procurement costs are likely to be excessive, it can avoid those costs by self-procuring some or all its customers' RA needs. Likewise, the Commission could direct the IOUs to fully self-procure RA capacity to meet their bundled needs to minimize the need to pay RA-CPE procurement costs.

Even assuming, however, that the Commission has authority over the charges paid by LSEs to meet § 380 requirements, parties' criticisms are premature. The scope of any appropriate oversight will depend on the entity that performs the RA-CPE role. If, for example, the RA-CPE is a state agency, coordination may be more appropriate than "oversight." Alternatively, if the IOU fulfills the RA-CPE role, direct regulation will be required because the entity is a public utility; even more will be required because the IOU competes in both the wholesale and retail markets with other generators who will sell into the RA-CPE solicitations and other LSEs on whose behalf the RA-CPE will procure. Finally, if the RA-CPE is a third-party, competitively neutral entity, another oversight paradigm may be appropriate. Consequently, it is important to first identify the RA-CPE before establishing an oversight framework.

In summary, the question of oversight, while understandably important, is left open by the Settlement Agreement for consideration following selection of the entity (or entities) that will be RA-CPE(s). Therefore, the Commission should not view the Settlement Agreement as being deficient for not fully addressing what are necessarily still unresolved RA-CPE oversight issues.

C. The Settlement Agreement Does Not Prevent Selecting an IOU as RA-CPE, and Such Selection Is Not the Sole Avenue to Avoiding FERC Jurisdiction

The Public Advocates Office asserts that the RA-CPE framework could prevent the Commission from adopting one or more of the utilities as a CPE, which is an action it suggests is necessary to avoid inviting Federal Energy Regulatory Commission ("FERC") involvement. It bases its argument on a provision requiring an LSE that recovers costs through consolidated billing to recover RA-CPE costs as a part of the generation component of the LSE's rates.[46] From there the Public Advocates Office jumps wildly, without connecting the dots, to the conclusion that somehow this Settlement Agreement will prevent the Commission from selecting an IOU as RA-CPE. It then takes another flying leap to the conclusion that not relying on an IOU as RA-CPE will invite FERC involvement.[47] Finally, it concludes that "constraints on cost recovery requirements and related impacts on CPE selection are not in the public interest."[48]

Nothing in the Settlement Agreement expressly precludes selecting an IOU as the RA-CPE. To the extent that there are hurdles to such a selection, however, they lie in, among other things, the reasonable and, in the Settling Parties' view, necessary requirement that the RA-CPE be "competitively neutral"[49] and not, as the Public Advocates Office suggests, in the Settlement Agreement's cost allocation provisions. Thus, while other concerns may prevent the selection of an IOU as RA-CPE, the fact that the IOU would be required to include the RA-CPE costs in the generation rate of its component would have no apparent bearing on its suitability for the job.

It is also critical to note that placing an IOU in the RA-CPE role is *not* the only way in which to maintain the state's jurisdiction over its function. The Public Advocates Office, again,

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46 Public Advocates Office Comments at 12.
47 *Id.* at 13.
48 *Id.*
49 Joint Motion, Appendix A, § II.D. at 2.

fails to explain why an IOU is the only option for the RA-CPE that will not invite FERC jurisdiction. The Settling Parties submit that whether FERC intervenes in California's RA program will depend not on the entity serving as RA-CPE, but rather on *how the program is designed*.

FERC has permitted state programs in several contexts where state and federal jurisdiction overlaps. 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.[50] 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…."[51] Likewise, FERC established a framework for "consideration of transmission needs driven by Public Policy Requirements in the local and regional transmission planning processes,"[52] including, for example, renewable portfolio standards.[53]

The critical issue with respect to the risk of FERC intervention is whether the adopted program is "tethered" to or directly impacts participation in the wholesale market. In *FERC v. Elec. Power Supply Ass'n*,[54] the Supreme Court observed that the Federal Power Act ("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

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50 *Order 719*, 125 F.E.R.C. ¶61,071, at *459-60 (Oct. 17, 2008) (amending 18 C.F.R § 35.28).
51 *Id*. at *128.
52 *Order 1000*, 136 F.E.R.C. ¶61,051, at *217 (July 21, 2011).
53 *Id.* at *81.
54 136 S.Ct. 760 (2015).

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]

Case law 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

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55 *Id.* at 773 (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)).
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. ¶61,145, 61,747 (Nov. 17, 2011)).

organized market.[61] The Supreme Court agreed: "By adjusting an interstate wholesale rate, Maryland's program invades FERC's regulatory turf."[62]

State programs that provide support for generators *separate from and independent of market operations* have been found not preempted by federal law. "State law claims are not preempted…where the action does not relate to wholesale sales in interstate commerce…or where claims do not require the court to second-guess rates or tariffs set by FERC."[63] For example, *Electric Power Supply Ass'n. v. Star*[64] addresses an Illinois program to provide support for nuclear plants. Under the program, nuclear plants received emission credits which other types of generation were required to purchase. The price of the credit varied based on wholesale market prices. Differentiating from the fatal feature of the Maryland program, the Seventh Circuit allowed the program, finding that the subsidy did not depend on participation in the wholesale market, or directly affect wholesale prices:

> To receive a credit, a firm must *generate* power, but how it sells that power is up to it. It can sell the power in an interstate auction but need not do so. It may choose instead to sell power through bilateral contracts with users (such as industrial plants) or local distribution companies that transmit the power to residences.[65]

In *Coalition for Competitive Electricity v. Zibelman*,[66] the State of New York enacted a similar zero-emissions credit ("ZEC") program providing financial support to nuclear plants independent of their participation in wholesale auctions. The Second Circuit found the program was not preempted because its effect on wholesale markets was indirect.[67] The program also

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61 *Id*. (quoting *PPL EnergyPlus, LLC v. Nazrian*, 753 F.3d 467, 476-77 (4th Cir. 2014)).
62 *Id*. at 1297.
63 *E. & J. Gallo Winery v. EnCana Energy Servs.*, 2005 U.S. Dist. LEXIS 24240, at *26-27 (Sept. 30, 2005).
64 904 F.3d 518 (7th Cir. 2018).
65 *Id*. at 523-24.
66 906 F.3d 41 (2d Cir. 2018).
67 *Id*. at 54.

provided for credits to be given to resources with no carbon emissions and sold to those with emissions. The court acknowledged that the additional revenue from the sale of the credit may allow the resource to submit a lower bid in a wholesale market. It held, however: "Even though the ZEC program exerts downward pressure on wholesale electricity rates, that incidental effect is insufficient to state a claim for field preemption under the FPA."[68] Relying on language in *Hughes*, the court found FERC had no jurisdiction because there was no impermissible "tether" between the ZEC program and wholesale market participation.

The Public Advocates Office has not identified any characteristic of the RA-CPE framework that would "tether" it to or directly impact wholesale market participation. The Public Advocates Office's contention is thus groundless.

D. The Settlement Agreement's Provisions for Recovery of RA-CPE Costs in the Event of LSE Default Are Consistent with the Law

The Settlement Agreement makes the RA-CPE "revenue neutral" and thus socializes the costs of default among LSEs on whose behalf the RA-CPE procures RA.[69] Some parties object to the methodology applied to ensure RA-CPE cost recovery in the event of an LSE default. SCE asserts that allocating costs due to an LSE's default to the remaining LSEs is inappropriate and would result in unlawful cost shifting among customers.[70] PG&E claims that the proposed allocation methodology is contrary to equitable principles of cost allocation.[71] The Public Advocates Office believes that the methodology could lead to inequitable ratepayer cost recovery.[72]

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[68] *Id.*
[69] Joint Motion, Appendix A, § VII.E.2.
[70] SCE Comments at 6.
[71] PG&E Comments at 13-14.
[72] Public Advocates Office Comments at 11-12.

As a preliminary matter, the Settlement Agreement's proposed methodology is consistent with the CAISO's treatment of the costs of defaults for payment of backstop procurement.[73] In addition, both SCE and PG&E supported this approach in prior stakeholder processes before the CAISO.[74] Accordingly, the Commission should dismiss these criticisms as unwarranted in its evaluation of the Settlement Agreement.

IV. THE SETTLEMENT AGREEMENT'S PROVISIONS REQUIRING THE RA-CPE TO DEMONSTRATE COLLECTIVE COMPLIANCE WITH RA REQUIREMENTS FURTHERS RELIABILITY

Some parties raise concerns with the Settlement Agreement's shift from individual LSE requirements to a collective RA-CPE requirement.[75] To the contrary, this feature of the RA-CPE framework is an improvement over the status quo. Placing a Collective Residual Requirement on the RA-CPE leaves the final responsibility (before CAISO backstop) to a single entity with the authority and tools necessary to get the job done. Moreover, the argument rings particularly hollow when considering the full procurement or hybrid procurement models advocated by PG&E and SCE would have no individual requirements for local RA.

The California Large Energy Consumers Association ("CLECA") contends that by allowing an LSE to rely on the RA-CPE for all of its procurement, the Settlement Agreement violates § 380(b)(5) by reducing CCAs' ability "to choose their generation resources and

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[73] See Section 43A.8 of the CAISO Fifth Replacement Electronic Tariff.

[74] Notably, both PG&E and SCE are parties to a settlement in FERC Docket No. EL09-62 which sets forth how defaults in the CAISO's markets are to be allocated. CAISO market defaults are allocated broadly to other participants in the CAISO market; similarly, the Settlement Agreement proposes to allocate LSE default costs to other LSEs. While parties argue that it may not be "equitable" to allocate one party's default costs to other parties, such socialized allocation has precedent and may be the best way to keep credit risks and costs low.

[75] Comments of Vistra Energy Corp. on the Settlement Agreement for a "Residual" Central Procurement Entity Structure for Resource Adequacy, (Vistra Comments) at 3-4. SCE also contests the elimination of the individual LSE requirements, but its grounds the argument in concerns regarding oversight, which are addressed in Section V.C.

impacting the Commission' policy of customer choice."[76] CLECA further contends that "it would homogenize the resource mix and eliminate the opportunity for cost differences among LSEs," which CLECA contends is contrary to the law.[77]

The Settling Parties fully recognize the need to protect LSEs' choice of resources for serving their customers; in fact, the Settlement Agreement is designed to do just that. An LSE may elect to self-procure all or any portion of its needs, consistent with § 380(b)(5). The Settlement Agreement does not undermine that election in any way. Moreover, if CLECA believes eliminating this election would be unlawful, then the full and hybrid procurement models favored are indefensible in that they would completely undermine the ability of LSEs to self-procure the local resources that they might prefer. Choice and individual LSE responsibility are removed under those models, just as CLECA fears.

Vistra raises the concern that this provision will result in LSEs leaning on the RA-CPE for any shortfall, knowing that they "will not be exposed to RA-CPE costs greater than the soft offer cap."[78] Vistra further concludes that procurement price cap is unlikely to provide incentives to develop new resources.[79] As an initial matter, the RA-CPE may pay more than the soft-offer cap if circumstances warrant;[80] an LSE thus cannot assume that reliance on the RA-CPE will necessarily limit its costs. Moreover, as discussed in Section V.E below, neither the RA-CPE framework outlined in the Settlement Agreement nor, for that matter, the RA Program, is intended to be the primary tool to provide incentives for new resources.

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[76] Response of the California Large Energy Consumers Association Opposing the Joint Motion for Adoption of a Settlement Agreement (CLECA Comments) at 7.
[77] *Id.* at 7-8.
[78] Vistra Comments at 4.
[79] *Id.*
[80] Joint Motion, Appendix A, § III.C.6. at 4.

V. THE SETTLEMENT AGREEMENT IS A PARTIAL SETTLEMENT, AND THE PRESENCE OF OPEN ISSUES DOES NOT DETRACT FROM ITS VALUE IN ADVANCING THE COMMISSION'S GOAL OF IMPLEMENTING A CENTRAL PROCUREMENT MECHANISM

A number of parties raise concerns that the Settlement Agreement does not answer all the questions attendant to a central procurement mechanism. For example, SCE complains that the Settlement Agreement "does not include all elements of a workable implementation solution for the central procurement of multi-year local RA, or appropriately address all known challenges to the local RA program."[81] The Settling Parties note that open issues will not change the fundamental structure of the RA-CPE framework regardless of their resolution. The Settling Parties have identified issues that will require either further collaboration among parties or a Commission decision.[82] The fact that issues remain thus should not detract from the value of the Settlement Agreement in advancing the Commission's goal to implement a central procurement mechanism.

A. The Settlement Agreement Substantially Addresses the Issue Categories Identified in the Track 2 Decision

SCE recites the issue categories identified in D.19-02-022 for resolution in any central buyer proposal.[83] As discussed in Section I of these Reply Comments, the Settlement Agreement meets most of these requirements in greater detail than any other proposal brought to the Commission to date.

The Settlement Agreement makes clear the scope of procurement, including its residual nature,[84] the responsibility for ensuring that aggregate RA requirements are satisfied,[85] the

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81 SCE Comments at 30 (text case modified).
82 Joint Motion at 17-18.
83 SCE Comments at 30 (citing D.19-02-022 at OP 4).
84 Joint Motion, Appendix A, § III.A. at 2.
85 *Id.*, § III.B. at 3.

products to be procured by the RA-CPE, [86] and responsibility for procurement to meet collective deficiencies. [87] The Settlement Agreement further provides a detailed cost allocation mechanism that could be implemented with minimal refinement. [88] In addition, the Settlement Agreement provides a detailed mechanism and process for LSE and CPE procurement,[89] including a price cap for RA-CPE procurement that will mitigate seller market power. [90] Finally, the Settlement Agreement also provides a very detailed timeline for the RA process, identifying dates for every key activity.[91]

However, certain issues were not addressed, including the RA-CPE's identity and detailed resource selection criteria, because the Settling Parties themselves had polarized views on these elements. Therefore, in order to reach consensus in the short time allotted by D.19-02-022, the Settling Parties focused on the primary components of the procurement framework that resolved the majority of issues. The Settling Parties explain below why the issues were left for further stakeholder collaboration or Commission actions. In addition, the discussion addresses market power mitigation tools, which the Settling Parties submit have been addressed adequately to the extent such tools fall within the Commission's jurisdiction.

B. The Identity of the RA-CPE Could Not Be Resolved in the Time Provided Due to the Polarization of Views

The most significant open issue, as noted by TURN, SCE, and AWEA-LSA, is the identity of the RA-CPE.[92] The Settling Parties recognized early in their discussions, however,

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86 *Id.*
87 *Id.* § III.A. at 2.
88 *Id.*, § VII. at 8 and Appendix B.
89 *Id.,* § III.C. at 3.
90 *Id.*
91 *Id.,* Appendix A.
92 TURN Comments at 1; SCE Comments at 19; AWEA-LSA Comments at 3.

that they would be unable to agree on the identity of the RA-CPE; some parties favor a state governmental entity and others favor a third-party entity. Recognizing the unlikely resolution of this issue before the Commission's year-end target for adoption of a central procurement mechanism, the Settling Parties agreed to leave this issue open, as specified in Section C.7. of the Settlement Agreement.[93] And while implementation details may differ depending upon the ultimate choice of RA-CPE, the framework proposed by the Settlement Agreement can be implemented whether the RA-CPE is a state governmental entity, a third-party entity or an IOU. Consequently, while the Commission and, potentially, the Legislature will need to designate an RA-CPE, the Settling Parties' inability to resolve this issue does not detract from the legitimacy or value of the Settlement Agreement.

C. Protocols for RA-CPE Oversight Will Depend Upon the Identity of the RA-CPE

SCE complains that "there is very little discussion of a Commission oversight process in the Settlement Agreement," noting that the provisions instead point to coordination of the RA-CPE activities with the Commission, the CAISO, and the California Energy Commission ("CEC").[94] The Public Advocates Office likewise argues that the Settlement Agreement "[f]ails to provide for sufficient oversight of the Central Procurement Entity (CPE) by the Commission."[95] The Public Advocates Office cites insufficient oversight of contract costs, formation and administrative costs, and creditworthiness and collateral protocols.[96] Both parties start from the premise that cost and rate regulation of the RA-CPE is required – a premise that warrants examination. Moreover, the Settlement Agreement is necessarily light on details with

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93 Joint Motion, Settlement Agreement at 5.
94 SCE Comments at 31.
95 Public Advocates Comments at 1.
96 *Id.* at 8.

respect to the RA-CPE's oversight in large part because the extent and nature of such oversight will depend upon whether the RA-CPE is a "sister" state agency, a third-party entity, or an IOU.

Assessing the need for RA-CPE oversight requires an examination of the Commission's obligations under § 380. While the Commission has jurisdiction over services provided and rates charged by the IOUs, its RA authority does not extend that same jurisdiction to services provided and rates charged by a CCA or an ESP. The Commission's primary role in the state's RA program is to make sure that all LSEs procure enough of the right types of capacity to ensure reliability. While it is the Commission's responsibility to ensure that the IOUs' RA costs are just and reasonable, but the exercise of that authority falls under § 451 and § 380 (g). In other words, it is the Commission's business to ensure that LSEs obtain the right type of capacity to ensure reliability; it is not the Commission's business to oversee the prices at which LSEs meet their obligation, with the exception of the IOUs. Thus, the notion that the Commission should maintain authority to oversee and approve the costs, rates and charges of the RA-CPE is suspect.

Moreover, the RA-CPE's procurement costs are, in effect, self-regulating. If an LSE believes that the RA-CPE's procurement costs are excessive or are likely to be excessive, it can avoid those costs by self-procurement. Indeed, the Commission could direct the IOUs to fully self-procure RA to meet their needs to minimize the need to pay these costs. (As for RA-CPE administrative costs, the workshop discussion revealed that such costs are likely to be largely the same regardless of what entity fulfills the RA-CPE role, except only perhaps for an already existing state agency.) The Settlement Agreement provides opportunities for the Commission to review the effectiveness of the procurement, two years after inception, as well as no later than five years to review the need for the RA-CPE in the future. Parties would have opportunities to provide feedback to the Commission with regards to the administrative costs at those times.

Even assuming, however, that the Commission had authority over the charges paid by LSEs to meet § 380 requirements, SCE's and the Public Advocate's Office's criticisms are premature. The scope of any appropriate oversight will depend to a large degree on the entity that performs the RA-CPE role. If, for example, the RA-CPE is a state agency, coordination may be more appropriate than "oversight." Alternatively, if an IOU fulfills the RA-CPE role, a more expansive hand of regulation may be required due to the fact the IOU competes with the entities on behalf of whom it would be procuring RA. Finally, if the RA-CPE is a third-party entity, another oversight paradigm may be appropriate. Consequently, it is important to first identify the RA-CPE before establishing an oversight framework.

D. The Settlement Agreement Recognizes That Resource Selection Criteria Will Benefit from a Broader Range of Stakeholder Input

Parties also raised the absence of criteria for the RA-CPE's selection of resources to meet the RA requirements.[97] CESA raises its concern that:

> [T]he Joint Settlement Agreement has structured the centralized RFO process for residual RA needs to only focus on least-cost procurement of reliability resources at or below the soft-offer cap set for the Capacity Procurement Mechanism ("CPM"). The detailed evaluation criteria are not provided, though the Joint Settlement Agreement describes how the CPE should take into "account" other factors such as state energy policy objectives.[98]

The Settling Parties agree that transparent selection criteria will be important in ensuring the success of the RA-CPE framework. The Settling Parties concluded, however, that broader stakeholder input was needed to resolve the issue than was possible to accommodate in the time provided, and that the criteria need not be developed prior to adoption of the RA-CPE structure envisioned by the Settlement Agreement. Therefore, the Settlement Agreement expressly

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97 Comments of California Energy Storage Alliance (CESA Comments) at 4.
98 *Id*.

provides for the development and adoption of selection criteria “by the Commission through a public process.”[99] That process, which can be implemented well in advance of the first RA-CPE procurement solicitation, will provide parties the opportunity to propose criteria that will help ensure that the RA-CPE’s procurement actions are consistent with the state’s energy policies.

VI. OPPOSING PARTIES’ PURPORTED CONCERNS REGARDING THE ROLE OF THE RA-CPE ARE NOT VALID

Parties opposed to the Settlement Agreement express concern that under the framework proposed in the Settlement Agreement, LSEs would no longer have the obligation to procure capacity to meet the reliability needs of the grid because the Settlement Agreement has shifted this obligation to the RA-CPE.[100] Parties suggest further that the RA-CPE proposal is not sufficiently coordinated with the IRP proceeding. These concerns are misplaced. Broadly speaking, the proposed RA-CPE framework is conceptually no better or worse than the full and hybrid procurement models in this regard, and it in no way interferes with the Commission’s efforts in the context of the IRP proceeding.

Parties’ purported objection to the role of the RA-CPE makes little sense given that both the full and hybrid procurement frameworks reflect the philosophy that shifting procurement responsibility entirely to a central procurement entity is the optimal approach to ensuring reliability. Indeed, under PG&E’s full procurement model, “the CPE has *sole* responsibility for meeting local reliability compliance requirements on behalf of all LSEs.”[101] As PG&E explains, “[u]nder a Full Procurement Model, LSEs are not given local RA requirements, and the entire quantity of needed local RA is procured by a CPE.”[102] Likewise, the hybrid model eliminates

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99 Joint Motion, Appendix A, § III.C.2. at 3.

100 *See, e.g.* PG&E Comments at 9; SCE Comments at 20.

101 Joint IOU Informal Report, Appendix 1-13 (emphasis added).

102 PG&E reply comments to parties’ proposals, dated August 8, 2018, at 1-2 Line 8.

mandatory local RA requirements for LSEs.[103] Thus, *all* of the currently-active CPE proposals in this proceeding incorporate the basic concept of the CPE, rather than LSEs, having primary responsibility for procuring the resources needed to ensure grid reliability. The Settlement Agreement also incorporates this concept, but leaves intact the § 380 requirements to maximize LSE procurement autonomy.

While the proposed RA-CPE framework would make the RA-CPE primarily responsible for ensuring system reliability, it does not interfere with LSEs' ability to self-procure. The Settlement Agreement framework is limited in scope to the method and amount of capacity the RA-CPE must procure in order to meet the multi-year forward reliability needs *after* LSEs have elected to show the capacity they have already self-procured consistent with their IRP plans approved or certified by the Commission. If an LSE procures more RA than its share of the Collective RA Requirement due to changes in its load forecast, then the LSE may transact bilaterally with other LSEs or offer its excess capacity into the RA-CPE's annual solicitation. If an LSE was unable to procure sufficient capacity bilaterally, then the RA-CPE in its annual solicitation would attempt to procure capacity on the LSE's behalf in order to meet the LSE's share of the Collective RA Requirement.

The full procurement model, on the other hand, eliminates LSE procurement autonomy, in violation of § 380 (b)(5), given the risk that the CPE will not select resources owned or contracted by LSEs. Under the full procurement model, if the CPE does not select an LSE's resources to meet the Local reliability needs, the LSE can use the Local resource only to meet its System and Flexible capacity needs. This increases the LSE's cost of System and Flexible procurement because it relegates premium Local products to meeting the System/Flexible

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[103] Joint IOU Informal Report, Appendix 1-17.

obligations. In addition, under the full procurement model, the LSE would be allocated additional costs by the CPE for the portion of its Local capacity that was not selected. The stranded cost risk inherent in the Full procurement model could dis-incentivize LSEs from developing Local resources entirely.

Some parties argue that the RA-CPE procurement price cap "is insufficient to create incentives for the entry of new resources …."[104] The Settling Parties agree that the Settlement Agreement alone, with its three-year term and procurement price cap, may be insufficient to bring a significant amount of new resources to the market. However, the need for new resources is an issue for the IRP proceeding, and the design of a mechanism to incent the development of new resources is more properly a task for that proceeding. Consequently, the Settlement Agreement expressly defers to the IRP "a process for planning for the development of new RA resources needed for reliability."[105] The Settling Parties note, however, that implementation of the stable forward procurement mechanism proposed in the Settlement would facilitate development of new resources by providing a mechanism for parties to efficiently transact their long and short positions on a rolling three-year forward basis.

Finally, the proposed RA-CPE does not interfere in any way with the IRP process or LSEs' development of their long-term resource portfolios. All LSEs must submit individual integrated resource plans to the Commission on a biennial basis. The IRPs present analysis based upon approved resource assumptions that demonstrates a path to achievement of the State's carbon mitigation goals in a reliable and cost-effective manner through reliance on existing and/or new resources. The Settlement Agreement makes no change to this requirement. Indeed, the multi-year forward central procurement function contemplated in the RA-CPE aligns

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[104] Powerex Comments at 5-6. *See also* Vistra Comments at p. 2-3, Joint DR Comments at 8-9.
[105] Joint Motion, Appendix A, § VI.H. at 7.

closely with the "backstop" mechanism currently under consideration in the "procurement track" of the IRP proceeding.

PG&E correctly notes that the Commission has expressed concerns regarding system reliability in the IRP proceeding.[106] In D.19-04-040, the Commission identified a need for "mechanisms for 'backstop' procurement, in the event that an individual LSE or LSEs fail to procure the resources identified in their IRPs as necessary to fulfill their responsibilities for procurement."[107] The Commission notes further that it intends to coordinate this "backstop" function with the instant RA proceeding. Thus, the RA-CPE does not impede the conduct of the IRP proceeding or prevent adoption of requirements related to long-term procurement of capacity resources. Rather, if anything, the RA-CPE could serve as a template for the IRP backstop mechanism in the future.

A. The Proposed RA-CPE Framework Does Not Increase the Potential for Inefficient Procurement

Both PG&E and SCE assert that the Residual procurement framework proposed in the Settlement Agreement causes procurement inefficiency, pointing to the fact that the proposed Residual procurement model counts LSEs' Shown RA capacity on a megawatt-for-megawatt basis without accounting for "effectiveness." PG&E and SCE suggest different meanings for the term "effectiveness," each of which is addressed below.

PG&E defines the term "'effective' as a resource with high availability and 'ineffective' as one with low availability."[108] Based on this definition, the Settling Parties understand PG&E to be referring to resources with use-limitations or limited duration. The fundamental question that is at the root of PG&E's concern is whether RA counting rules are accurate. For example, in

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106 PG&E Comments at 9-10.
107 D.19-04-040 at 139.
108 PG&E Comments at 10, fn 27.

Track 3 of the RA proceeding as well as more recent RA working group meetings held September 5-6, 2019, PG&E has proposed to modify the qualifying capacity ("QC") counting rules for hydro resources in order to better reflect the resource's availability.[109] PG&E has explained that the current QC methodology does not accurately reflect the resources' actual production amount because it does not capture the variability of annual "hydrological conditions, weather patterns, [FERC] licensing, storage levels and upstream and downstream powerhouses…"[110]

The Settling Parties agree that accurate counting methodologies are crucial to ensure that both LSEs and the RA-CPE procure sufficient capacity to meet reliability needs. This is an issue that must be addressed in the RA proceeding to ensure that "effective" resources are developed to meet long term reliability needs. In addition, the RA proceeding should continue to refine the methodologies to ensure accurate counting of resources. More broadly, however, the Settling Parties note that this issue is not unique to the residual procurement model and would apply to both the full and hybrid procurement models. PG&E provides no evidence that the full procurement model would be able to address issues with RA effectiveness any better than any other model. PG&E's assumption that under the full procurement model, the CPE would be able to limit procurement to highly-available resources and meet reliability needs without any low-availability resources for all areas in the absence of clear RA counting rules that encourage such procurement is questionable. In addition, as a practical matter, "ineffective" resources are necessary to meet the Local area requirements in some areas.

SCE does not expressly define "effectiveness," but generally suggests that "effectiveness" is a resource's ability to address various local reliability issues identified in the

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109 PG&E's proposal dated March 4, 2019, at 10-11.

110 *Id.* at 9

CAISO's annual Local Capacity Technical Study. It is neither possible nor necessary to predetermine resource effectiveness factors for crediting LSE-provided local capacity resource. As CAISO has indicated, given that the effectiveness factors are defined with respect to specific contingencies and may depend on what other resources are procured, it is not obvious how a CPE under the full approach could determine which resources are optimally "effective" relative to all the constraints that must be enforced in its procurement.

B. The Proposed RA-CPE Framework Would Not Result in Stranded Local RA Capacity

PG&E asserts that the RA-CPE construct proposed in the Settlement Agreement could create stranded local RA capacity and/or result in double-procurement of System RA capacity.[111] PG&E posits, for example, that if an LSE were long on local capacity and had a sufficient mixture of local and system capacity to meet its share of the Collective System RA Requirements, the Settlement Agreement would limit the LSE from showing surplus Local RA to meet incremental system RA requirements, which would cause the LSE to need to self-procure additional system RA capacity or else depend on the RA-CPE to procure the additional system RA capacity on its behalf.[112]

The Settlement Agreements allows an LSE to do exactly what PG&E suggests should be allowed. While the proposed RA-CPE construct includes constraints on how much an LSE may show to the RA-CPE, an LSE is nevertheless able to show its excess Local RA capacity as System RA capacity in order to meet its share of the collective System RA requirements: recognizing that resource NQCs vary monthly and that LSEs may have self-procured additional RA capacity to serve its customers, the Settlement Agreement allows LSEs to use surplus Local

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111 PG&E Comments at 12-13.
112 *See* PG&E Comments at 13, Table 1.

capacity to meet their share of the additional System and Flexible collective RA requirements.[113] However, this utilization of excess of Local RA capacity may limit the RA-CPE from procuring sufficient Local RA capacity to meet Local reliability needs. In such an instance, the RA-CPE would not procure additional System RA, and there would therefore be no additional System RA costs to allocate.

The showing constraints set within the Settlement Agreement were crafted based on numerous hours of careful deliberations and multiple scenario analyses. One of the core principles of the Settlement Agreement is that procurement cost allocation must follow cost causation. The Settling Parties were concerned that in the absence of a showing constraint, an LSE would be incentivized to procure beyond its share of the Collective RA Requirement and show the surplus Local RA capacity to ensure that it would receive a payment for its excess Local RA procurement. Essentially, the LSE would be able to "put" its excess procurement to the CPE. The showing constraint incentivizes LSEs to bilaterally transact so that their shown RA generally matches their needs for all three products while providing multiple vehicles for selling any capacity in excess of need.

In summary, the Settling Parties believe the Settlement Agreement has struck the balance needed to prevent unintentional withholding and leaning among LSEs.

C. The CAISO's RA Enhancement Initiative is Not an Impediment to Adoption of the Proposed RA-CPE Framework

Both TURN and SCE comment that the Settlement Agreement creates a disincentive for LSEs to "show" excess RA and that this runs counter to the CAISO's RA Enhancements initiative.[114] As a threshold matter, the Settling Parties note that the full procurement model does

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113 Joint Motion, Appendix A, § V.D.4. at 7.

114 TURN Comments at 3; SCE Comments at 26-27.

not allow any LSE to "show" capacity to the CPE and neither the full nor hybrid models contemplate procurement of capacity beyond the reliability needs. In addition, the CAISO acknowledges that it may need to modify its RA Enhancements proposal in response to the Settlement Agreement, noting "CAISO would need to open a formal stakeholder process to fully consider the necessary changes."[115] Thus, CAISO appears to be willing to undertake CAISO Tariff changes in order to implement the proposed RA-CPE framework.

VII. SCE'S PROPOSED "MODIFICATIONS" ARE ANTITHETICAL TO THE SETTLEMENT AGREEMENT AND SHOULD BE REJECTED IN THEIR ENTIRETY

SCE offers the Commission several "ideas" for potential modifications to the RA-CPE framework proposed in the Settlement Agreement. These modifications, while not yielding a fully-developed proposal, would result in a Residual procurement model proposal that departs significantly from what has been proposed by the Settling Parties. SCE's proposed modifications, which in any event are largely unworkable, should therefore be rejected.

First, SCE appears to advocate in favor of "a residual model in which there is no upfront requirement or valuation of any potential requirements."[116] This suggestion is clearly at odds with the concern expressed elsewhere in SCE's comments regarding shifting of the obligation to ensure grid reliability to the CPE. The complete elimination of upfront requirements would result in a lack of transparency – it would make it difficult for LSEs to evaluate the procurement activities of the CPE or to raise concerns regarding over-procurement of Local RA capacity.

Second, SCE proposes to impose a three-year forward procurement requirement with a 100 percent Local RA requirement for all three years.[117] SCE reasons that raising the Year 3

115 CAISO Comments at 3.
116 SCE Comments at 36.
117 *Id*.

Local RA target percentage to 100 percent will eliminate the need for the CPE to track cost causation.

Table 1 below compares the Local RA Requirement Target Percentages proposed under each construct:[118]

Table 1

Local RA Requirements Target Percentage	Year 1	Year 2	Year 3
Current Multi-Year Framework	100%	100%	50%
Settlement Agreement	100%	100%	75%
SCE's Modified Proposal	100%	100%	100%

Under SCE's proposal, the CPE would allow LSEs to show their three years of forward capacity in order to determine the residual amount of Local capacity that the CPE must procure. However, SCE's proposal would freeze the three-year forward requirement and would not account for load forecasting changes associated with a multi-year procurement construct. SCE explains that "[w]ith a 100% requirement three-years forward, there is no need to allow incremental procurement in future periods and no need to implement complex methods to determine what was bought for which LSE at which point in time."[119] This proposal could actually threaten reliability, however, if forecasted load increased for years 2 and 3 compared to when originally forecasted and neither LSEs nor the CPE are allowed to procure incremental capacity. SCE also ignores the negative impact such requirements would have on potential development of new resources through LSE procurement of locally-preferred resources.[120]

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118 It is unclear how SCE intends to apply these target percentages when there would be no upfront requirements in the first place.

119 SCE Comments at 36

120 The Settlement Agreement, in contrast, leaves "room" for new, locally-preferred and self-procured resources to come online in Year 3.

SCE previously noted that "it could prove costly to procure 100% of forecast local area requirements five years forward if unpredicted changes in consumption or changes to the transmission grid obviated the original need in subsequent years. This issue can be addressed by 'layering in' procurement annually, such that 100% procurement does not occur sooner than two years forward, to mitigate the risk of such occurrence."[121] SCE does not address in its current proposal the rationale supporting its change in position. SCE's proposed modifications would provide little benefit, serving merely to lock in local RA resources for three years forward based on a snapshot of load at a single point in time. LSEs would procure only for the future "Year 3" as time rolls forward since the resources for the rolling Years 1 and 2 are always procured and committed.

Finally, SCE proposes various rules to administer cost allocation and ensure that the LSE and generators have "sufficient credit and collateral to ensure that if the LSE finds itself over-hedged, it does not simply remove the resource from its subsequent RA showing with no obligation on the generator to still perform."[122] The ability to remove a resource from future RA showings would appear to contradict SCE's proposal for the supplier to submit "three-year forward supply plan for the RA resource."[123] Assuming SCE's proposal provides the ability for LSEs and suppliers to submit new RA and supply plans for the subsequent three years, then the question that must be considered is why the LSE must be required to continue to show the resource if it is excess to its requirement or if the LSE no longer has a procurement obligation. Continuing to show the resource would serve no obvious purpose beyond allowing other LSEs to benefit from that LSE's surplus.

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[121] SCE Track 2 Testimony, July 10, 2018, p 12, Lines 18-22.
[122] SCE Comments at 38.
[123] *Id.* at 37.

The Settling Parties contemplated many related issues during the settlement discussions that resulted in the constraints laid out in the Settlement Agreement. The Settlement Agreement allows an LSE to bilaterally transact shown RA capacity with another LSE if load decreases,[124] or to offer the previously shown RA to the RA-CPE. Under SCE's proposal, the second option is removed entirely, and LSEs would have limited ability to optimize their portfolios or to minimize any potential financial penalties from the CAISO for being an RA resource.[125]

SCE further proposes that the CPE collect costs directly from customers in the event of an LSE's default and have "the IOUs serve as the CPE for their individual TAC areas with costs allocated to all load within the TAC."[126] SCE's proposal to designate the IOU to serve as the central buyer in its TAC is outside the scope of the issues addressed in the Settlement Agreement. Thus, SCE's proposal is inapposite and should not be considered by the Commission in connection with approval of the Settlement Agreement.

VIII. THE SETTLEMENT AGREEMENT'S USE OF THE "SOFT OFFER CAP" IS REASONABLE

A few parties have criticized the Settlement Agreement's incorporation of the "Soft Offer Cap" for backstop procurement under the CAISO's Capacity Procurement Mechanism ("CPM") or its successor. As explained below, those criticisms are misplaced or misapprehend the Soft Offer Cap's intended function under the proposed RA-CPE framework. Before the Settling Parties address those criticisms, however, it is important to understand the purpose of the CPM and the function of the Soft Offer Cap in the CAISO context.

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124 SCE did "object to LSEs trading among themselves to change their hedged position provided the resource is still shown for RA." SCE Comments at 36.

125 CAISO currently assesses financial penalties to RA resources based on the resource's availability under the RA Availability Incentive Mechanism ("RAAIM").

126 SCE Comments at 39.

As some parties have pointed out, potential changes to the CPM are currently being examined in the CAISO's CPM Soft Offer Cap stakeholder process. In its most recent CPM Soft Offer Cap straw proposal, the CAISO explained the purpose of the CPM as follows:

> Resources procured as resource adequacy capacity are required to be available to the ISO to meet the load-serving and reliability needs of the grid. Occasionally, there are resources that want to retire but cannot as they are essential to maintaining grid reliability. When this happens, the ISO can use its reliability must-run (RMR) authority to retain these essential reliability resources and defer their retirement until new resources are built or transmission is enhanced. There are also situations when resources or capacity procured [by LSEs] through the resource adequacy program are not sufficient to meet the load-serving and reliability needs of the grid. If this happens and if additional capacity is not procured [by LSEs] to cure the deficiency, the ISO relies on its CPM authority to procure the needed capacity to meet the needs of the grid.[127]

The CAISO also provided a concise description of the CPM's operation:

> The CAISO attempts to first use bids from the competitive solicitation process from non-resource adequacy capacity when making CPM designations. Resource owners have the opportunity to bid capacity, for total or partial output from a specific resource, into this process. This process is not mandatory, and non-resource adequacy capacity is under no obligation to bid into the competitive solicitation process. However, if a bid for capacity is accepted and awarded a CPM designation, the resource is obliged to accept the CPM award and the associated obligations. These obligations include a must offer obligation and making the awarded capacity subject to the ISO's Resource Adequacy Availability Incentive Mechanism (RAAIM) tool, which provides financial incentives for resources to meet their resource adequacy obligations.[128]

The CAISO then explained the function of the CPM Soft Offer Cap as follows:

> Market power mitigation for the competitive solicitation process is provided through a soft offer cap. The soft offer cap is a proxy for the system marginal capacity cost and serves as a "safe harbor" capacity value that owners are allowed bid up to, and receive that value if designated for

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[127] CAISO, *Capacity Procurement Mechanism Soft Offer Cap Straw Proposal*, Jul. 24, 2019 ("*CPM Soft Offer Cap Straw Proposal*"), at 5. A copy of the CPM Soft Offer Cap Straw Proposal is posted on the CAISO's website at http://www.caiso.com/Documents/StrawProposal-CapacityProcurementMechanismSoftOfferCap.pdf.

[128] *CPM Soft Offer Cap Straw Proposal* at 5-6.

> a CPM award. [Footnote: Resources are able to bid above the soft offer cap, but these costs need to be verified by the ISO, prior to awarding a CPM designation.] The resource owner does not have to justify any bid at or below the soft offer cap to receive that payment for a CPM designation. Currently, the soft offer cap is set at $75.67/kW-year, or $6.31/kW-month.[129]

The Settlement Agreement contains two substantive provisions that reference the CPM Soft Offer Cap.[130] The Soft Offer Cap's intended function under those provisions is twofold. First, it acts as a price "cap" on the bids the RA-CPE will accept, on a least-cost basis, until the residual RA requirements for each month of the applicable delivery period have been met. This will mitigate the need for CAISO backstop procurement by: (1) ensuring that the RA-CPE will procure, on a least-cost basis, those RA resources that are needed to meet the residual RA requirements but were not picked up by LSEs through their bilateral contracting; (2) ensuring the RA-CPE will not simply defer to the CAISO the procurement of needed resources that are priced at or near the Soft Offer Cap; and (3) eliminating the incentive for suppliers to withhold capacity from the RA market in the hope of their resources being procured at a higher price through the CPM process.

Under the Settlement Agreement, the Soft Offer Cap also acts as a "trigger" for both (a) the requirement that a supplier provide an explanation for why a higher price is reasonable and (b) the requirement that the RA-CPE perform a reasonableness analysis that takes into consideration Commission-approved procurement criteria and the information provided by the supplier.[131] These requirements will ensure that the RA-CPE will only procure resources at

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[129] *CPM Soft Offer Cap Straw Proposal* at 6.

[130] Joint Motion, Appendix A, §§ III.B and III.C.6. at 3-4.

[131] *Id.*, § III.C.6. at 4.

prices above the Soft Offer Cap when, on both a practical level and a policy basis, it is reasonable to do so.

The Department of Market Monitoring ("DMM") expresses two concerns that are specific to Settlement Agreement's use of the CPM Soft Offer Cap.[132] First, DMM observes that "the CPM Soft Offer Cap is only one element of the CAISO's backstop procurement authority, which includes a combination of various CPM and [RMR] tariff provisions," and notes potential changes to these backstop procurement mechanisms are currently under consideration.[133] DMM's concern here appears to be that Soft Offer Cap that "could be replaced with an entirely different CPM compensation method designed to mitigate potential market power due to the lack of competitiveness in the CAISO's capacity procurement process."[134] DMM also expresses concern that "the current Soft Offer Cap may be based on an estimate of the going forward fixed costs of resources in the California market that is several fold greater than actual going forward fixed costs of most resources."

DMM's objection to the Settlement's use of the CPM Soft Offer Cap seems to be that the RA-CPE may end up paying more for certain RA-CPE resources (i.e., prices up to the *current* Soft Offer Cap) than the CAISO would pay for the same resources under a revised (and presumed lower) Soft Offer Cap or some other "CPM compensation method." However, the Settlement Agreement expressly contemplates the possibility that the CPM Soft Offer Cap will be revised. It does so by defining "Soft Offer Cap" as the CPM "offer cap" that is specified in the CAISO Tariff.[135] The Soft Offer Cap under the Settlement Agreement will therefore be the

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132 DMM has a third concern that it relates to the Settlement's use of the Soft Offer Cap but is more accurately related to the Settlement Agreement's provision limiting the RA-CPE's procurement authority to RA products only.

133 DMM Comments at 1.

134 DMM Comments at 1-2.

135 Joint Motion, Appendix A, § I.J. at 2.

same as the CPM Soft Offer Cap specified in the CAISO Tariff, whatever it may be. The Settlement also contemplates the possibility that the CPM will be replaced with some other mechanism, in which case the Soft Offer Cap under the Settlement Agreement will change to whatever the "offer cap" may be under the CPM successor mechanism. If the existing CPM compensation method (*i.e.,* the awarding of bids up to the "offer cap" with the opportunity for sellers to justify higher prices) changes, then parties can petition the Commission to modify the RA-CPE solicitation protocols accordingly.

A different criticism of the Settlement Agreement's use of the Soft Offer Cap is that it could serve to prevent new, potentially higher priced resources (e.g., energy storage) from competing in the RA-CPE's solicitations.[136] However, the Settlement Agreement expressly provides that the RA-CPE's solicitations will be open to both existing and new resources.[137] The Settlement Agreement also provides that the RA-CPE's procurement decisions will take into account the effectiveness of resources in meeting state energy policy objectives.[138] In addition, the Settlement Agreement expressly allows the RA-CPE to accept bids at prices above the Soft Offer Cap where the higher prices are properly justified and procurement of the resource in question is consistent with Commission-approved selection criteria.[139] While the Settling Parties have not attempted to dictate what those criteria might be, we fully expect that the criteria will include a resource's contribution toward meeting the state's clean energy goals. In light of these provisions, the Settling Parties respectfully submit that concerns about the ability of new resources—whose costs may exceed the CPM Soft-Offer Cap—to compete in the RA-CPE's solicitations are misplaced.

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136 Vistra Comments at 2; CESA Comments at 4;

137 Joint Motion, Appendix A, § III.C.1. at 3.

138 *Id*., § III.C.2.c. at 3.

139 Id., § III.B. at 3.

In contrast to other proposals on the record, the Settlement Agreement provides an actual price cap and transparency whereas other proposals do not. The Energy Division's multi-year proposal defers this decision to the judgement of the CPE "to decide when it would be better for the resource to be procured through the annual backstop mechanisms…" and requires an independent evaluation to report on market power. PG&E's full procurement proposal would also defer the procurement decision to the CPE while raising any market power concerns to the CPUC in a filing to select between two portfolios the CPE suggests for procurement. SCE's hybrid procurement proposal also would allow the CPE to procure without a price cap and defer the judgement of market power to the Commission by reasoning "the central buyer is not obligated to procure if the Commission believes the proposed procurement is not reasonable…" In all of these cases, either the CPE will have the option to make a subjective judgement call, which would lead to non-transparent selection process, or the CPE would defer to the Commission through a procedural filing, which may prolong the procurement process and delay contract execution. In contrast, the Settlement Agreement provides a clear and transparent constraint on RA-CPE procurement that effectively addresses market power concerns.

IX. THE SETTLEMENT AGREEMENT, CONTRARY TO SCE'S CLAIM, MITIGATES COMPLEXITIES INHERENT IN A MULTI-YEAR CENTRAL PROCUREMENT MECHANISM

SCE contends that "the Settlement Agreement's proposed residual model introduces a significant amount of complexity because of the difficulty in addressing cost allocation related to load migration under a residual model."[140] SCE's Hybrid proposal is simple, i.e., allocate all CPE costs to all load on a load share basis. It achieves this simplicity, however, by imposing additional complexity on LSE bilateral procurement. For example, under the SCE approach, an

[140] SCE Comments at 24.

LSE must make complicated tradeoffs about whether to retain capacity or sell it to the CPE and how to hedge its system and flexible RA positions in light of the uncertainty about what capacity it might lose by selling to the CPE and what system and flexible attributes it might be allocated by the CPE. In both the full and hybrid procurement models, these "complexities" are not clearly identified but are still part of the cost allocation process.

In addition, SCE's concerns about the complexity of CPE cost allocation under the Settlement Proposal are misplaced; the fear that "the complexity can quickly grow to a point where it may not be controllable or sustainable"[141] is simply not supported by the facts. To the contrary, the specificity presented in the Settlement Agreement proposal provides clarity by addressing the complexity inherent in a multi-year RA framework, and proposing detailed and workable mechanisms. Rather than rejecting the Settlement Agreement, the Commission should focus on ensuring smooth implementation of the Settlement Agreement through constructive refinements of the proposed framework in an open forum.

A. The Settlement Agreement Mitigates the Complexity of New Entry and Load Migration Inherent in a Residual Model

SCE exaggerates the complexity of the Settlement Agreement with vague scenarios that the Settlement Agreement addresses:

> Additional complexity arises when more complicated scenarios are involved, such as how the model would accommodate the entry of a new LSE when existing LSEs and the CPE have already procured sufficient local capacity to meet a specific local (or sub) area requirement. Although the proposal has some mechanisms to encourage the sale from LSEs that lose load such that load gaining LSEs can meet their own needs, it is not clear how this mechanism can be administered while ensuring that central procurement costs are not inappropriately shifted among LSEs.[142]

[141] SCE Comments at 25.
[142] SCE Comments at 24.

SCE's contention fails to demonstrate flaws in the proposal in three ways. First, SCE alludes to but does not describe multiple "more complicated scenarios" (except for one, addressed below). Second, it invokes the "cost shift" label without explaining whose costs are shifting to whom or how. Third, SCE observes that the Settlement Agreement has mechanisms that allow for resource trading to address load migration, but alleges it fails to explore these mechanisms and demonstrate how they might lead to cost shifting.

The Settlement Agreement uses three primary tools to address load migration and new entry (the sole "complicated" scenario raised by SCE). First, the Settlement Agreement leaves a percentage margin for future procurement for Year 3 for Local RA Requirements and, for Years 2 and 3 for System and Flexible RA Requirements as well; this leaves flexibility for LSEs to make adjustments for migrating load.[143] The Settlement Agreement also allows LSEs to bilaterally transact their shown RA capacity,[144] thereby enabling an LSE that is losing load to sell its Shown RA capacity to a new entrant that may be receiving the migrating load. The Settlement Agreement also allows LSEs that lose load to reduce their showing or sell their now "excess" RA to the RA-CPE.[145] All of these options allow and incentivize LSEs to optimize their portfolios to reduce any excess capacity just as any LSE would do today.

B. Load Forecast Error is Inherent in the Multi-Year Construct that Any Framework Must Identify and Resolve

In its recitations of purported complexities, SCE also points to cost allocation in the case of load forecast error. SCE states:

> It also appears that even if an LSE procures an exact amount based on its actual load, it may be allocated a share of the CPE procurement cost (likely due to load

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143 Joint Motion, Appendix A, § III.B. at 3.
144 Joint Motion, Appendix A, § V.D. at 6.
145 *Id*.

> forecast error), which adds to the complexity regarding whether this cost allocation is appropriate compared to an alternative allocation mechanism.[146]

Load forecasts change annually based on a variety of factors that the California Energy Commission takes into consideration when it establishes the forecast. The Settlement Agreement specifically addresses load forecast error when load declines year over year and the RA-CPE has procured additional capacity than would now be needed to meet the Residual RA Requirement. This forecast error would occur in both the full and hybrid models and the costs of the over procurement would also be allocated to all impacted LSEs per the respective cost allocation mechanisms. In effect, the cost allocation due to forecast error is the same between the full, hybrid and residual procurement models with the exception that the residual model clearly distinguishes over-procurement due to load forecast error.

C. The Complexity Arising from *Ex Ante* Actions and *Ex Post* Cost Allocation Will Be Present in Any Multi-Year Program

SCE claims that the Settlement Agreement is flawed due to "a combination of actions taken based upon ex ante determinations (*e.g*., load forecasts for the entire local area and that of individual LSEs) and ex post determinations (*e.g*., actual load served and actual procurement of local resources) in order to arrive at a cost allocation."[147] SCE contends that "this introduces additional complexity not presently in the RA structure and should be avoided." This statement is inaccurate. The current CAM process, one recommended by both PG&E and SCE, allocates capacity to LSEs based on LSEs' ex ante forecasts while costs are allocated to the LSEs on an ex post basis. The Settlement Agreement would not create or impose any additional complexity beyond that which exists today.

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146 SCE Comments at 24.
147 SCE Comments at 24.

SCE suggests that its preferred approach will avoid any of these concerns. It claims:

> [A] full front-stop procurement model can be much more direct and efficient in addressing the underlying cost allocation issues related to load migration. A full procurement model will provide certainty in how the central procurement cost is allocated without the complexity otherwise seen from the proposed residual model.[148]

SCE attempts to claim that its approach is superior only because its ability to accurately reflect cost causation and seamlessly address load migration *has not been vetted*. Providing "certainty" in the method of cost allocation is not necessarily an improvement on the Settlement Agreement, which allocates costs on cost causation principles. SCE also ignores the fact that while the cost allocation of its central procurement approach might be simple, it significantly complicates bilateral procurement.

X. OTHER ISSUES

A. The Settlement Agreement's Proposed Three-Year Limit on Contract Terms for RA-CPE Procurement Represents a Reasonable Compromise of Interests

The Settlement Agreement enables the RA-CPE to procure RA products for a term of up to three years.[149] CAC challenges this value as being "adequate for merchant gas-fired generation facilities….[but[the profile is inapplicable to CHP operations."[150] CAC states that for "CHP and UPG operations, major maintenance overhauls occur in 5-year cycles."[151] CAC continues:

> Truncating the RA contract term sends a counterintuitive message to the operator to defer or avoid maintenance that cannot be financially covered under the term of the PPA. This means the generating facility is not as reliable as it would be with a fully-funded maintenance schedule. [152]

148 SCE Comments at 24.
149 Joint Motion, Appendix A, Section III.C.5.
150 CAC comments at 9.
151 *Id.*
152 *Id.*

In making this argument, CAC erroneously equates the term of agreement with the length of maintenance cycles. However, it is not apparent, as CAC suggests, that a generating resource would enter into a contract that does not cover its maintenance costs and, as a result, operate less reliably. Moreover, nothing in the Settlement Agreement precludes a generator from recovering the costs of its five-year major maintenance cycle through a three-year contract, through multiple three-year forward procurement cycles, or through contracting for longer terms bilaterally. Finally, the Settlement Agreement's creation of a three-year system RA requirement adds more security than a system CHP resource has today under the year-to-year RA compliance cycles.

As with many aspects of the Settlement Agreement, the three-year contract term limitation represents a compromise among parties who may have preferred a shorter or longer term of RA-CPE commitment.

B. The Settlement Agreement Maintains the Status Quo for Allocation and Use of MIC Rights

Powerex proposes modifications to the Settlement Agreement's provisions regarding the availability and allocation of Maximum Import Capability ("MIC") rights.[153] In doing so, Powerex goes beyond the scope of the Settling Parties' intended treatment of MIC rights, which focused solely on the purchase or sale of such rights by the RA-CPE. Indeed, Powerex proposal arguably steps into the CAISO's domain. The Settling Parties did not intend, nor is this the proper forum to address, the CAISO's rules governing the allocation and use of MIC rights.

Instead, the Settlement Agreement addresses MIC rights very narrowly. It provides that the "RA-CPE may procure any maximum import capability (MIC) rights needed to facilitate the

153 Powerex Comments at 6-7.

procurement of import RA Capacity."[154] It further provides that LSEs may offer unused MIC rights to the RA-CPE in its annual RFO process.[155] The Settlement Agreement thus foundationally assumes that the availability and allocation of MIC rights will remain a subject that is addressed by the CAISO and subject to FERC jurisdiction.

XI. CONCLUSION

For all the foregoing reasons, the Settling Parties submit that the Settlement Agreement demonstrably addresses the Commission's requests and the known challenges to the current RA program and represents a significant step toward improving the existing RA framework. The Settling Parties therefore respectfully request that the Commission adopt the Settlement Agreement in its entirety and without modification.

Respectfully submitted,

Evelyn Kahl

EVELYN KAHL
Counsel to the California Community Choice Association

October 15, 2019

BN 38058482v1

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[154] Joint Motion, Appendix A, Section III.C.4.
[155] *Id.*, Section V.C.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2019 and 2020 Compliance Years.	R.17-09-020 (Filed September 28, 2018)

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S MOTION TO SHORTEN TIME TO RESPOND TO MOTION FOR STAY OF DECISION 19-10-021

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October 24, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2019 and 2020 Compliance Years.	R.17-09-020 (Filed September 28, 2018)

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S MOTION TO SHORTEN TIME TO RESPOND TO MOTION FOR STAY OF DECISION 19-10-021

Pursuant to Rule 11.1(e) of the California Public Utilities Commission (Commission) Rules of Practice and Procedure, the California Community Choice Association (CalCCA)[1] respectfully submits this Motion to Shorten Time to Respond to CalCCA's Motion for Stay of Decision 19-10-021 (Motion for Stay), filed and served by CalCCA concurrently herewith. CalCCA requests that parties' responses be due within two (2) business days, or by October 28, 2019, to allow the Commission to issue a decision on CalCCA's Motion for Stay as soon as practicable.

CalCCA's Motion for Stay requests the Commission to immediately stay Decision 19-10-021 (Decision), addressing Resource Adequacy (RA) import rules, for purposes of the October 31 and November 17 compliance showings and any additional showings until the Commission issues a decision on the Application for Rehearing, which is filed and served concurrently with

[1] California Community Choice Association represents the interests of 19 community choice electricity providers in California: Apple Valley Choice Energy, CleanPowerSF, Clean Power Alliance, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Monterey Bay Community Power, Peninsula Clean Energy, Pioneer Community Energy, Pico Rivera Innovative Municipal Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Jacinto Power, San Jose Clean Energy, Silicon Valley Clean Energy, Solana Energy Alliance, Sonoma Clean Power, and Valley Clean Energy.

this Motion. Good causes exist to shorten parties' time to respond to CalCCA's Motion for Stay.[2] Under Rule 11.1(e), parties have 15 days to respond to written motions "unless the Administrative Law Judge sets a different date." Given the negative impact of the Decision on most, if not all, parties involved, CalCCA does not anticipate any opposition to this Motion to Stay. If a party does decide to submit a response, a shortened two-day response period is non-prejudicial because CalCCA's Motion for Stay is short (less than nine pages) and presents a straightforward issue. Moreover, parties wishing to respond to the real issue at hand, the Application for Rehearing of D.19-10-021, will have ample time and opportunity to do so.

Most crucial, the October 31, 2019 compliance date is quickly approaching, and with it, the potential noncompliance penalties. Due to this potential harm, CalCCA respectfully requests the Commission expedite its consideration of CalCCA's Motion for Stay so that all potentially affected parties will not begin to incur penalties because of D.19-10-021.

October 24, 2019

Respectfully submitted,

Evelyn Kahl

Evelyn Kahl

Counsel to
the California Community Choice Association

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[2] *See* Decision (D.)05-04-020, Sept. 7, 2005 (applying a "good cause" standard to a motion to shorten time for response).

PROPOSED ORDER

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2019 and 2020 Compliance Years.	R.17-09-020 (Filed September 28, 2018)

ORDER GRANTING MOTION TO SHORTEN TIME

Pursuant to Rule 11.1 of the Commission Rules of Practice and Procedure, I hereby shorten response time to the *Motion for Stay of Decision 19-10-021* by two (2) business days, or by October 28, 2019.

This order is effective today.

Dated October , 2019, at San Francisco, California.

/s/
Administrative Law Judge

BEFORE THE PUBLIC UTILITIES
COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2019 and 2020 Compliance Years.	R.17-09-020

NOTICE OF SETTLEMENT CONFERENCE BY

CALIFORNIA COMMUNITY CHOICE ASSOCIATION, CALPINE CORPORATION, INDEPENDENT ENERGY PRODUCERS ASSOCIATION, MIDDLE RIVER POWER, NRG ENERGY, INC., SAN DIEGO GAS & ELECTRIC COMPANY, SHELL ENERGY NORTH AMERICA (US), L.P., SUNRUN, INC., AND THE WESTERN POWER TRADING FORUM

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Counsel to the
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August 9, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2019 and 2020 Compliance Years.	R.17-09-020

NOTICE OF SETTLEMENT CONFERENCE

Pursuant to Rule 12.1(b) of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission"), the California Community Choice Association, Calpine Corporation, the Independent Energy Producers Association, Middle River Power, NRG Energy, Inc., San Diego Gas & Electric Company, Shell Energy North America (US), L.P., Sunrun, Inc., and the Western Power Trading Forum ("Joint Parties") submit this notice of a settlement conference in the above-referenced proceeding.

The settlement conference will discuss the establishment of a residual resource adequacy central procurement framework. A settlement proposal will be distributed on or about August 16, 2019, to provide parties an opportunity to prepare for the settlement conference.

The settlement conference will be held on August 20, 2019, from 10:00 a.m. to 4:00 p.m. at the California Independent System Operator Corporation (CAISO), 250 Outcropping Way, Folsom, California, in the Ampere/Tesla room. If you are planning to attend the meeting in person, the CAISO requests you RSVP (https://caiso.regfox.com/rasettlements-aug20-2019) by close of business August 16, 2019. A web conference will also be available for remote participation:

Dial-in: 1-877-369-5230; Access Code: 0210689##
Join web conference: https://ems8.intellor.com/login/817088.
AT&T technical support: 1-888-796-6118

If you have logistical questions, you may contact Shagun Tougas, Clean Energy Regulatory Research, on behalf of CalCCA at s.tougas@CleanEnergyRegResearch.com.

Dated: August 9, 2019

Respectfully submitted,

Evelyn Kahl

Evelyn Kahl Counsel to the
California Community Choice
Association

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2019 and 2020 Compliance Years.	Rulemaking 17-09-020 (Filed September 28, 2017)

RESPONSE OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION IN SUPPORT OF THE JOINT MOTION TO ESTABLISH A SCHEDULE AND PROCESS FOR DETERMINING THE CAPACITY VALUE OF HYBRID RESOURCES

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October 11, 2019

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

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2019 and 2020 Compliance Years.	Rulemaking 17-09-020 (Filed September 28, 2017)

RESPONSE OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION IN SUPPORT OF THE JOINT MOTION TO ESTABLISH A SCHEDULE AND PROCESS FOR DETERMINING THE CAPACITY VALUE OF HYBRID RESOURCES

Pursuant to Rule 11.1 of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure, the California Community Choice Association (CalCCA)[1] submits the following response in support of the *Joint Motion to Establish a Schedule and Process for Determining the Capacity Value of Hybrid Resources*, filed on September 27, 2019 (Joint Motion).

I. INTRODUCTION

The Joint Motion requests a schedule and process for determining the qualifying capacity (QC) value of hybrid resources[2] "located in front of the utility meter (IFM) and behind the utility meter (BTM), which currently do not have a QC value or methodology to determine that value."[3] The Joint Parties seek to address the "lack of a timeline for establishing a QC methodology for

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1 California Community Choice Association represents the interests of 19 community choice electricity providers in California: Apple Valley Choice Energy, CleanPowerSF, Clean Power Alliance, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Monterey Bay Community Power, Peninsula Clean Energy, Pioneer Community Energy, Pico Rivera Innovative Municipal Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Jacinto Power, San Jose Clean Energy, Silicon Valley Clean Energy, Solana Energy Alliance, Sonoma Clean Power, and Valley Clean Energy.

2 "Hybrid resources" are generally defined as energy storage combined with a generation resource.

3 *Joint Motion to Establish a Schedule for Determining QC Value of Hybrid Resources* (Joint Motion), Sept. 27, 2019, at 1.

hybrid generation resources."[4] The Joint Parties' concern is borne from the representations at the Resource Adequacy (RA) workshops that "the Commission finds the determination of a QC methodology for hybrid customer-sited resources to be out of scope or otherwise untenable."[5] The Joint Parties request a ruling setting a schedule and process for adopting a QC methodology for hybrid energy resources[6] and a commitment to "adopting an interim methodology for determining that value before the end of 2019."[7] CalCCA supports the Joint Parties' request and urges the Commission to expeditiously set a schedule for consideration of this important issue.

II. CALCCA SUPPORTS THE REQUEST FOR EXPEDITED REVIEW OF THE HYBRID RESOURCE QC METHODOLOGY IN THE RA DOCKET

While CalCCA appreciates the Commission's establishment of a working group to resolve outstanding issues regarding the QC methodology, CalCCA shares in the Joint Parties' concern regarding the lack of a timeline for establishing a QC methodology for hybrid generation resources. As the schedule currently stands, a QC value of hybrid resources is not expected until mid- to late-2020. This timeline prevents the timely development of a procurement program for hybrid resources, which impairs the development and contracting efforts of load serving entities (LSEs) and hybrid resource generators. Ultimately, delay does a disservice to the state's climate goals and the end-use customers supporting LSEs' efforts to meet these goals. Therefore, CalCCA supports the Joint Parties in their request that the Commission commit to addressing the QC methodology before the end of 2019.

The Joint Parties clearly identify all of the signposts pointing to an urgent need to undertake this action. In particular, the proposed decision in R.16-02-007 magnifies the need to

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[4] *Id.* at 2.
[5] *Id.*
[6] *Id.* at 5.
[7] *Id.*

move quickly, forecasting a potential shortfall of system RA capacity as early as 2021.[8] With the short time for development, hybrid resources may be one of the most promising solutions to such a shortfall, as the Proposed Decision itself acknowledges.[9] The lack of clear communication of the value of these resources through a stable QC methodology, however, threatens to slow their development.

III. CONCLUSION

For the foregoing reasons, CalCCA respectfully requests that the Commission establish an expedited process to the QC methodology for hybrid resources.

Respectfully submitted,

Evelyn Kahl

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Counsel to the
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October 11, 2019

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8 *See generally Proposed Decision Requiring Electric System Reliability Procurement for 2021-23* ("The need for system resource adequacy and renewable integration resources begins in 2021 and will extend through at least 2023.").

9 *Id.* at 38.

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Examine Electric Utility De-Energization of Power Lines in Dangerous Conditions	Rulemaking 18-12-005 (Filed December 13, 2018)

CALIFORNIA COMMUNITY CHOICE ASSOCIATION RESPONSES TO COMMENTS AND PROPOSALS FILED ON SEPTEMBER 17, 2019

CALCCA
ADVANCING LOCAL ENERGY CHOICE

October 15, 2019

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Table of Contents

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Examine Electric Utility De-Energization of Power Lines in Dangerous Conditions	Rulemaking 18-12-005 (Filed December 13, 2018)

CALIFORNIA COMMUNITY CHOICE ASSOCIATION RESPONSES TO COMMENTS AND PROPOSALS FILED ON SEPTEMBER 17, 2019

I. INTRODUCTION

The California Community Choice Association ("CalCCA"), the trade association representing Community Choice Aggregators ("CCAs"), appreciates the opportunity to submit the following responses to comments and proposals submitted by parties on September 17, 2019 in response to the *Assigned Commissioner's Phase 2 Scoping Memo and Ruling* issued August 14, 2019 ("Phase 2 Ruling"). CalCCA was granted party status in this proceeding via email ruling on June 17, 2019.

II. BACKGROUND

In the Phase 2 Ruling, the Commission requested that the Investor Owned Utilities ("IOUs") [1] specifically, and other parties as interested, provide proposals in response to several questions. CalCCA notes Decision ("D.") 19-05-042 directed that Phase 2 of this proceeding would consider issues that were outside the scope of Phase 1. Therefore, the Commission may find that the timeline established in the Phase 2 Ruling may need further adjusting to accommodate robust and adequate discussion of many of the suggestions, insights, and comments provided by the parties in their proposals. In the instant Rulemaking, the Commission is considering issues with very significant implications for the health, safety, and well-being of the public. Robust discussion of these issues is essential. While some issues require expedited resolution, for the most part, consideration of these issues should not be rushed. CalCCA reviewed all of the proposals and comments and generally

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[1] San Diego Gas & Electric ("SDG&E"), Southern California Edison ("SCE"), and Pacific Gas & Electric ("PG&E") collectively referred to as the IOUs.

distilled them into seven primary issues. On each of those issues, CalCCA has identified areas of agreement and disagreement, issues that should be addressed in a workshop setting and issues that ought to be addressed in new tracks of this proceeding.

III. COMMENTS ON PROPOSALS

Issue 1: Definitions And Standard Nomenclature

Critical Facilities And Infrastructure

CalCCA believes the variety of recommendations indicates the need for a stakeholder workshop to reach consensus on the nomenclature. Several parties proposed reasonable additions to the definition of Critical Facilities and Infrastructure ("CFI"). In addition to the facilities and infrastructure identified in CalCCA's proposal, CalCCA supports the following specific additions to the definition of CFI proposed in parties' comments:

- Facilities that have been designated by a local government entity as a staging site or shelter site.[2]
- Transportation facilities identified by the Commission in D.02-04-060, including navigation communication, traffic control, and landing and departure facilities for air and sea operations" and "rail rapid transit systems as necessary to protect public safety."[3]
- All primary, secondary, and post-secondary schools, including directly affiliated administrative facilities.[4]
- CalTrans facilities.[5]

In addition, CalCCA agrees with the Western States Petroleum Association ("WSPA") that petroleum-related facilities other than refineries should be included in the definition of CFI. However, CalCCA disagrees with WSPA's position that such facilities should be treated as CFI because of their economic importance. By definition, a Public Safety Power Shutoff ("PSPS") event

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2 *See* Rural County Representatives of California ("RCRC") Comments at 3. All further references and citations to "Comments" refer to Parties' September 17, 2019 Comments and Proposals in the instant Rulemaking unless otherwise noted.

3 City and County of San Francisco ("San Francisco") Comments at 3.

4 *See* Direct Acccess Customer Coalition ("DACC") Comments at 2.

5 *See* Terjung and Naylor Comments at 4-5.

has the potential to freeze or substantially limit economic output in the affected area. While it is true that the petroleum industry is a key economic sector for California and the nation as a whole, the same can be said for other essential economic sectors such as mining, agriculture, and manufacturing. However, it clear that not all farms, mines, and factories qualify as CFI. Petroleum-related facilities should only qualify as CFI to the extent that they deal with toxic, explosive, and flammable chemicals that could pose a risk to public safety if the facility loses electricity.[6]

A small number of parties opposed expanding the definition of CFI beyond the definition adopted in Phase 1,[7] and one party, SDG&E, argued that the current definition of CFI is "overly broad" and should be narrowed and aligned with definitions used by other state agencies.[8] These parties' arguments are fundamentally flawed, as they ignore the distinct purpose served by developing a definition of CFI that is specific to the PSPS context. Other agencies have defined CFI in the context of other specific threats, such as wildfires and terrorism. In the PSPS context, "CFI" consists of those facilities and infrastructure that rely on electricity, provide essential public health and safety functions or public services, and would experience significant disruption of their ability to provide these services if electric power were interrupted. A detailed, specific, and comprehensive definition of CFI and list of the facilities and infrastructure that qualify as CFI are essential to fulfilling the following basic PSPS response functions:

1. Identifying all CFI operators that need to be included in the IOUs' mandatory lists of primary and secondary 24/7 emergency contacts.
2. Ensuring that CFI operators receive priority notification (with documented confirmation) of PSPS events.
3. Identifying CFI that has the greatest need for PSPS resiliency resource funds.

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6 However, CalCCA believes that the potential economic impact of PSPS, including the potential economic impact on the petroleum sector and secondary impacts on consumers and the economy as a whole from interrupted operations of petroleum facilities, should be considered by the IOUs in deciding whether to de-energize a particular line or lines during a PSPS event.

7 *See*, *e.g.*, California Association of Small and Multi-Jurisdictional Utilities ("CASMU") Comments at 4.

8 *See* SDG&E Comments at 2.

4. Ensuring that all facilities that are essential to public health and safety or that provide critical public services have their backup generation needs assessed by the IOUs, and ensure IOU pre-approval for IOU-provided backup generation.[9]

Under SDG&E's proposal, a range of facilities that are critical for public health and safety would be removed from the definition of CFI. For instance, SDG&E's proposed definition would exclude 911 call centers, hospice care facilities, residential mental health facilities, and a significant number of other facilities and infrastructure that, in a PSPS event, is required to maintain public health, safety, and the provision of essential services.

A number of parties identified facilities and infrastructure that serve an important public function but are not currently included as an *essential* public service. For instance, libraries and post offices do not provide an essential public service of immediate and urgent need (unless a given library or post office has been designated as an emergency shelter or staging site). Similarly, CalCCA does not support the elevation of electric vehicle ("EV") chargers to critical infrastructure as proposed by the California Energy Storage Alliance ("CESA"),[10] since chargers and charging stations serve the same function as gas stations (providing fuel for vehicles), which are not currently considered critical facilities. During a PSPS event, fueling any vehicle (electricity or fossil fuel dependent) is likely to present a similar challenge of inability to "load" the vehicle (i.e., recharge or refuel).

PSPS Phase Nomenclature

CalCCA asks that when the Commission considers terms used for pre-, during, and post-PSPS, those terms be consistent, simple, understandable, and easy to translate into multiple languages. The PSPS terms should also be differentiated enough from disaster response terminology to avoid confusion or conflict with other statutes and regulations. Various parties have proposed differing PSPS terminology: PG&E proposes a nomenclature for the various stages of a PSPS event;[11] multiple parties provided variations of language for PSPS Phase names; and Mr. Abrams proposed replicating federal designations for event stages, including preparedness, response,

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9 *See*, D.19-05-042 at 73-74 ("the utilities must assist critical facility and infrastructure customers to evaluate their needs for backup generation and determine if additional equipment is needed, potentially including utility-provided generators for facilities that are not well prepared for a power shut-off")

10 *See* CESA Comments at 2.

11 *See* PG&E Opening Comments on Phase 2 Ruling at 3.

recovery, and mitigation.[12] Through a workshop, the Commission could ascertain appropriate terms for PSPS phases from stakeholders themselves. CalCCA also suggests that terms be adopted to distinguish between possible, planned, and (actual) ongoing PSPS events.

<u>Issue 2</u>*: *Vulnerable Customers / Increased Risk Individuals

The majority of parties that commented on the Medical Baseline issue agreed that the current Commission Rules and IOU practices for identifying and enrolling all eligible Medical Baseline Customers are inadequate and must be improved. SCE and SDG&E offered general acknowledgements that the Commission should refine the approach for Medical Baseline customers. Both the Joint Local Governments and San Francisco stress the importance of requiring that the IOUs work with local jurisdictions to identify and enroll eligible Medical Baseline customers.[13] The Utility Reform Network ("TURN") identifies Medical Baseline under-enrollment as an urgent problem, stating that "the profound underutilization of the Medical Baseline program should be addressed quickly and efficiently as possible."[14]

CalCCA strongly agrees that the IOUs should be required to significantly improve their practices for identifying and enrolling Medical Baseline customers, with a goal of 100% enrollment of all eligible customers. CalCCA further agrees that the IOUs should be required to coordinate closely with local jurisdictions to improve Medical Baseline enrollment.

Similarly, a number of parties noted the importance of identifying and taking steps to protect Access and Functional Needs ("AFN") customers. The Center for Accessible Technology ("CforAT") argued that the Commission should focus on methods outside the Medical Baseline designation to identify AFN customers and ensure that they are not put at risk during a de-energization event.[15] San Francisco argued that the Commission should require that the IOUs develop and regularly update lists of AFN persons, and provide targeted outreach to vulnerable populations by entering into data sharing agreements with agencies that provide services to AFN persons. CalCCA strongly agrees that AFN persons are at a substantially increased risk of harm during a PSPS event and that the IOUs are responsible for whatever steps are necessary to mitigate

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12 *See* Comments of William B. Abrams at 6.
13 *See* San Francisco Comments at 4.
14 TURN Comments at 3.
15 *See* CforAT Comments at 6.

this harm, including maintaining lists of AFN individuals, data-sharing with appropriate agencies, and targeted outreach.

However, as CalCCA noted in its Proposal, it is essential that the IOUs identify *all residents that are at a substantially increased risk of harm during a PSPS event*. Medical Baseline customers are one subset of a broader group of Increased Risk Individuals ("IRIs"), and AFN persons are another subset of IRIs. However, there are many IRIs that may not qualify for or be enrolled in the Medical Baseline program and do not meet the definition of AFN. Thus, while CalCCA supports requirements and program changes aimed at significantly increasing Medical Baseline enrollment, and proposed steps to improve protections for AFN persons, these alone may only partially address the need, leaving many vulnerable individuals that must be identified through other means. As noted by the City of San José, medical baseline tariffs are one way to identify individuals who need assistance during a PSPS event, but they are merely an economic billing program."[16] An IOU's list of Medical Baseline customers is not a comprehensive list of all individuals at an increased risk of harm due to a PSPS event. [17] As San José further notes:

> The program is not well-known and relies on individuals with enough knowledge to sign up for the special electrical rates/fees. But not everyone who requires electricity for life-supporting services (e.g., using a ventilator) will have signed up for this program and could therefore be missed during a PSPS." [18]

Identifying *all* IRIs is essential to mitigating the worst potential harms of PSPS outages. A complete list of IRIs, along with some kind of risk categorization, is essential for the utilities to (1) target priority notification (with documented confirmation); (2) notify authorities of customers at immediate, life-threatening risk during an outage (such as customers on electrically powered life-support equipment); and (3) identify the customers with the greatest need for resiliency resources.

CalCCA recognizes that identifying all IRIs is a large task that raises a number of policy, legal, and practical issues.[19] CalCCA proposes that the Commission initiate a separate, dedicated

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16 Comments of the City of San Jose at 4.

17 CalCCA Comments at 12.

18 *Id.* at 4.

19 CforAT Comments at 3 (noting that utilities might not be the best place to concentrate AFNs information and that the IOUs must take additional steps year-round to acclimate AFNs to PSPS events and to raise awareness of data sharing needs for AFNs populations. CforAT observed that low income AFNs or households without transportation may not have the listed means of communication that IOUs employ for notifying PSPS affected individuals.). CforAT also acknowledges that communication with AFNs requires special approaches beyond the standard established communication methods already established, at 9.

track of the instant Rulemaking focused on PSPS rules to protect Vulnerable Populations / IRIs. This track would include the consideration of PSPS-related issues as they apply to Medical Baseline, AFN, and all other IRIs, and should, at a minimum, address the following questions:

- Definition of IRIs (in addition to Medical Baseline and AFN customers):
    - What other groups should be included in the definition of IRIs?
    - Should IRIs be divided into "tiers" or otherwise categorized according to likelihood and potential severity of harm in a PSPS event? If so, how should these tiers be defined?
- How should the IOUs identify and track IRIs?
- What Commission oversight is required to ensure that the IOUs are adequately identifying IRIs and maintaining current contact information?
- What privacy protections or modifications to existing privacy rules are necessary to protect IRIs?
- What steps should the IOUs be required to take to ensure that IRIs have access to resiliency resources?

Some parties proposed that any matters relating to the Medical Baseline program be separated from this proceeding. CalCCA strongly opposes this proposal. Medical Baseline customers (and other IRIs) face a unique set of risks due to PSPS events, and mitigating these risks requires a set of IOU actions and requirements that are distinct to the PSPS context. Separating the Medical Baseline issue further risks creating a serious disconnect between inter-dependent issues, due to a separate record being developed and risks limiting participation of parties and misalignment with the progress in Phase II of this proceeding.

As part of this proposed Vulnerable Populations / IRIs track, CalCCA recommends that the Commission hold a at least one workshop with community-based organizations and local governments that have experience in communicating to AFN populations to identify further steps to take**.**

<u>Issue 3</u>*: *Transmission and Distribution

CalCCA agrees with PG&E that the Commission should establish clear, standard definitions for "transmission level PSPS" and "distribution-level PSPS."[20] However, CalCCA differs from

[20] PG&E Comments at 3.

PG&E in believing that it is essential that the Commission adopt a single standard definition for all IOUs. The definitions adopted by the Commission will affect communications and notifications, as well as designation of "transmission level" customers, and should be as clear and straightforward as possible. As is apparent from SCE and PG&E's comments,[21] the distinction between so-called "sub-transmission" and "distribution" lines is functional, depending on an electric system's design, and the voltage level that distinguishes between "sub-transmission" and "distribution" differs significantly between the IOUs. Rather than adopting separate definitions of "distribution" and "transmission" for each IOU to reflect this difference – an option which would almost certainly lead to significant confusion – CalCCA supports the Energy Producers and Users Coalition ("EPUC") proposal that the Commission adopt a single set of baseline definitions based on California Independent System Operator ("CAISO") control. "Transmission" lines and facilities would be those that have been transferred to CAISO control, and "distribution" lines and facilities would be those that remain fully under the control of the IOUs.[22] CalCCA agrees with the California Municipal Utilities Association ("CMUA") that clarification on this matter is necessary,[23] and proposes that the Commission hold workshops to clarify this baseline definition and determine if any further actions need to be taken to ensure compliance with CAISO rules and other regulatory requirements.

CalCCA is concerned by PG&E's statement that further clarity from the Commission on this topic is necessary "since the notification process and Federal Energy Regulatory Commission standards of conduct, for example, are different for transmission events than for distribution events."[24] This statement is very troubling, and implies that PG&E may be intending to withhold advance notice of transmission-related PSPS events to certain Public Safety Partners. CCAs need access to PSPS transmission-related information to modify their power scheduling to match the reduction in load due to the outage *as required by CAISO rules*. The Commission should clearly direct the IOUs to provide transmission-related PSPS information to all Public Safety Partners.

***Issue 4*: Public Safety Partner Access To PSPS Information**

CalCCA recommends the Commission initiate a new track in this proceeding to address concerns regarding access to confidential customer data. First Responders and Public Safety Partners

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21 *See* SCE Comments at 2-3; PG&E Comments at 3.
22 *See* EPUC Comments at 5-6.
23 *See* EPUC Comments at 5-6
24 PG&E Comments at 3.

need to access necessary data in advance of, and during, PSPS events to prepare response plans, evacuation and transportation plans, and resiliency center location evaluations. PG&E has limited access to this information by demanding that Public Safety Partners, including CCAs, execute overbroad and burdensome non-disclosure agreements ("NDAs"). These NDAs have been neither reviewed nor approved by the Commission, and would be enforced by PG&E, not the Commission. These NDAs reduce the ability of emergency responders and local governments to ensure public safety. CCAs have a broad right to relevant customer information, and are subject to the Commission's customer privacy rules, rendering any NDA requirement duplicative and unnecessary.[25] Other first responders and local government units are not similarly situated. As the Joint Local Governments point out, the IOUs' requirement that local governments sign unreasonably restrictive IOU-imposed NDAs might delay the dispatching of third-party resources like ambulances. The Commission explicitly recognized the information-sharing problems created by PG&E's NDA in President Batjer's October 14, 2019 Letter to PG&E. In this letter, President Batjer directed PG&E to take a range of immediate corrective actions, including:

> Develop processes and procedures for sharing information of medical baseline customers that can be impacted by a specific PSPS event…. the utilities are expected to share medical baseline information with counties and tribal governments, if requested, without a memorandum of understanding or non-disclosure agreement during PSPS events.[26]

The letter further directed PG&E to:

> Develop processes and procedures for sharing information on critical facilities with counties and local governments during events. This must include a solution for sharing information with counties and local governments even if there is no existing memorandum of understanding or non-disclosure agreement.[27]

CalCCA strongly agrees with these directives, and asks that the Commission explicitly extend them to CCAs, clarify that these directives apply to information both during and prior to PSPS events, and incorporate them into the PSPS Rules.

The Joint Local Governments note that the federal Health Insurance Portability and Accountability Act of 1996 ("HIPPA") establishes a framework that respects an individual's privacy while addressing the need for multiple parties to access the requisite information to provide medical care; it allows for sharing an individual's information without obtaining consent in each instance, and

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25 *See*, generally, D.12-08-045 (adopting customer information confidentiality rules for CCAs).

26 At 4-5.

27 *Id.* at 5.

in turn binds those who receive the information from disclosure. [28] CalCCA further with the Joint Local Governments that the Commission needs to take up the topic of confidential customer data and make it a priority. The Commission should ultimately adopt a single set of PSPS privacy and confidentiality rules that applies to all IOUs and Public Safety Partners to address the issues of medical baseline customers, rules on confidentiality, and AFNs needs as discussed in Issue 4, below. AFNs need improved and expanded communication. These are complex issues that merit a careful policy analysis that balances the needs of Public Safety Partners with personal or confidential information in order to avoid life-threatening situations and provide essential services with a variety of privacy and confidentiality considerations.

To address these complex issues, CalCCA requests that the Commission open an additional track in this Rulemaking to address the public safety and customer privacy implications of PSPS information-sharing with Public Safety Partners. The goals of this track should be to:

- Develop a single standardized NDA, or set of customer information privacy rules, for non-CCA Public Safety Partners that:
    - Does not impose unreasonable or burdensome terms on Public Safety Partners.
    - Allows adequate flexibility to share confidential information when necessary to protect life and property.
    - Is overseen and enforced by the Commission, not the IOUs.
- Consider any changes to existing IOU and CCA customer privacy rules that are needed for the PSPS context.

Because adequate information sharing is essential to protecting public safety, CalCCA asks that this proposed track be expedited.

***Issue 5*: Establishing Standardized PSPS Criteria**

Most of the parties that commented on Standardized PSPS Criteria agreed that some flexibility is necessary to allow the IOUs to account for regional variation and opposed the fixing of *absolute* criteria for PSPS. CalCCA agrees with these parties that, as a general matter, absolute criteria do not allow for the flexibility necessary to address differences between IOU territories, line states, vegetation, geography, and other factors. At the same time, CalCCA strongly supports the adoption of a "floor" for the IOUs – a minimum set of criteria that an IOU must consider, and

[28] *See* Joint Local Governments' Comments at 12.

analysis that the IOU must conduct, before initiating a PSPS event. This minimum analysis should consist of a balancing test that balances, on one hand, the likelihood and potential extent of harm from not deenergizing (measured as likelihood of ignition and the probability of the fire spreading), and, on the other hand, the likelihood and extent of harm caused by the PSPS. In its Proposal CalCCA provided a specific list of minimum criteria that should be considered by IOUs in this balancing test.[29] CalCCA urges the Commission to make the tracking, quantification or measurement (where appropriate), and consideration of each of these minimum criteria as mandatory for each IOU. Each IOU should be allowed to account for regional variation by assigning different weighting to the mandatory minimum criteria, or by including additional, region-specific criteria to its analysis.

A mandatory minimum set of criteria and balancing test methodology is needed to reduce disparities among IOUs. The Commission should hold a workshop on this topic. The Mussey Grade Road Alliance ("MGRA"),[30] for example, noted that from June 2019 to September 2019:

> SCE has issued 6 de-energization reports, PG&E has issued 1 de-energization report, and SDG&E and the small IOUs have issued none. The disparity between these numbers indicates that there may be a major difference in approach to shutoff criteria between the major utilities. [31]

MGRA further notes that the Commission should be concerned that SCE is on the verge of shutoffs so often.[32] The disparity may indicate that a standard set of criteria is warranted. The City of San Jose argues that criteria are necessary.[33]

Several parties opposed or expressed caution towards any level of standardized criteria. PG&E notes that while standardized criteria are appealing, there are variations among the IOU territories, that may work against standardization. The CASMU supports a non-standardized criterion that is process reflective, rather than fixed, explaining:

> Best practices or applicable criteria for assessing wildfire risk and/or de-energization events will vary for different utilities. Many tools used to assess and analyze landscapes or fire conditions are resource dependent. Small utilities, like the CASMU members, will not have the same resources or the same tools as the Large IOUs.[34]

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[29] CalCCA Proposal at 15-18.
[30] MGRA Comments at 7.
[31] *Id.* at 9.
[32] *Id.*
[33] *See* Comments of the City of San Jose at 11.
[34] Proposal of Bear Valley Electric Service (U 913 E), A Division of Golden State Water Company, Liberty Utilities (CalPECO Electric) LLC (U 933 E), and PacificCorp (U901 E) at 9.

The Public Advocates Office cautions the Commission against setting criteria that create rigid thresholds that could impair flexibility or incentivize adverse actions.[35] EPUC agrees the statewide criteria is useful but believes defining risk criteria by the service territory might better serve customers.[36] WSPA concurs that some criteria are needed, but warns that prescriptive criteria could be problematic for certain service areas based upon the terrain and electric wire conditions.[37]

These concerns are adequately addressed by CalCCA's proposal to allow regional variation in the weighting of mandatory minimum criteria and the consideration of additional criteria. Although most of the minimum criteria proposed by CalCCA consist of information all utilities should already have (i.e. records of line maintenance, pole type, conductor type, time since last brush clearing, etc.) a small handful of CalCCA's proposed criteria are somewhat resource dependent. For instance, vegetation moisture measurements may require the use of drone and satellite resources that some IOUs do not currently have in place. The Commission should reasonably accommodate the IOUs' starting points and allow for some degree of phase-in in establishing mandatory minimum criteria.

CalCCA agrees with the Joint Local Governments that the Commission should require that the IOUs' not only document the conditions the IOU used to evaluate the PSPS event, but also a transparent disclosure of the decision process, measured steps taken, and any additional variables the IOU used to determine whether or not to call a PSPS event.[38] If these details are incorporated, the Commission could use this information to establish standards to balance the potential safety benefits to be gained from PSPS against the potential harms caused by PSPS.

As a component of the risk assessment, WSPA recommends that the Commission call for a study and cost-benefit analysis of shutoffs, similar to the models used in the insurance industry.[39] The Utility Consumers Action Network ("UCAN") concurs, noting:

> Shutoff thresholds should be optimized through a risk/benefit or cost/benefit analysis and that remediation plans be put in place to strengthen infrastructure over time and raise shutoff thresholds. In particular, UCAN supports the suggestion that "in order for a utility to assert that it has used shut-off as a 'last resort,' it needs to demonstrate that it has clearly quantified the risks introduced by shutoff and showed them to be lesser than those of leaving lines energized.[40]

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35 *See* Proposal of the Public Advocates Office at 3.
36 *See* EPUC Comments at 10.
37 *See* Comments of WSPA at 7.
38 *See* Joint Local Governments' Comments at 18.
39 *See* WSPA Comments at 8.
40 UCAN Comments at 5.

If the Commission decides to consider a cost-benefit risk analysis, CalCCA recommends a workshop to allow stakeholders the opportunity participate the development of the methodology for making these calculations. Finally, CalCCA agrees with WSPA that the Commission should clarify that the IOUs are not immune to claims for consequential PSPS damages and liabilities caused by a PSPS event.[41] The questions of what those costs would be and how they would be allocated merits another track in this proceeding.

Issue 6*: *The Role of CCAs in PSPS

All the IOUs and several other parties agree that CCA notification responsibility with respect to a PSPS event is limited to acting in a supporting role. As SCE states, CCAs should not be primarily responsible for communication of PSPS events. Only the Small Business Utility Advocates ("SBUA") recommend that the CCAs should be required to communicate directly with customers regarding impending PSPS events. While CalCCA appreciates SBUA's acknowledgment of the relationships CCAs develop with their local commercial and industrial customers, the IOUs—as the grid operators and the ultimate PSPS decisionmakers—are in the best position to serve in the primary communication role. CCAs lack the immediate access to the necessary information to adequately and accurately serve as the front lines of communications about PSPS events. CalCCA generally agrees with the IOUs that state the CCAs should refer questions about PSPS events to the IOU which delivers the power in their respective areas consistent with PG&E's and SCE's Electric Rule No. 23 C5(a) and SDG&E's Electric Rule 27.

CalCCA is open to discussion about how CCA roles may change in preparation for PSPS events in the future. The comments here regarding the role of CCAs in PSPS focus on notification and communication. The CCAs could also play important roles in raising PSPS awareness and developing PSPS mitigation measures, such as micro-grids.

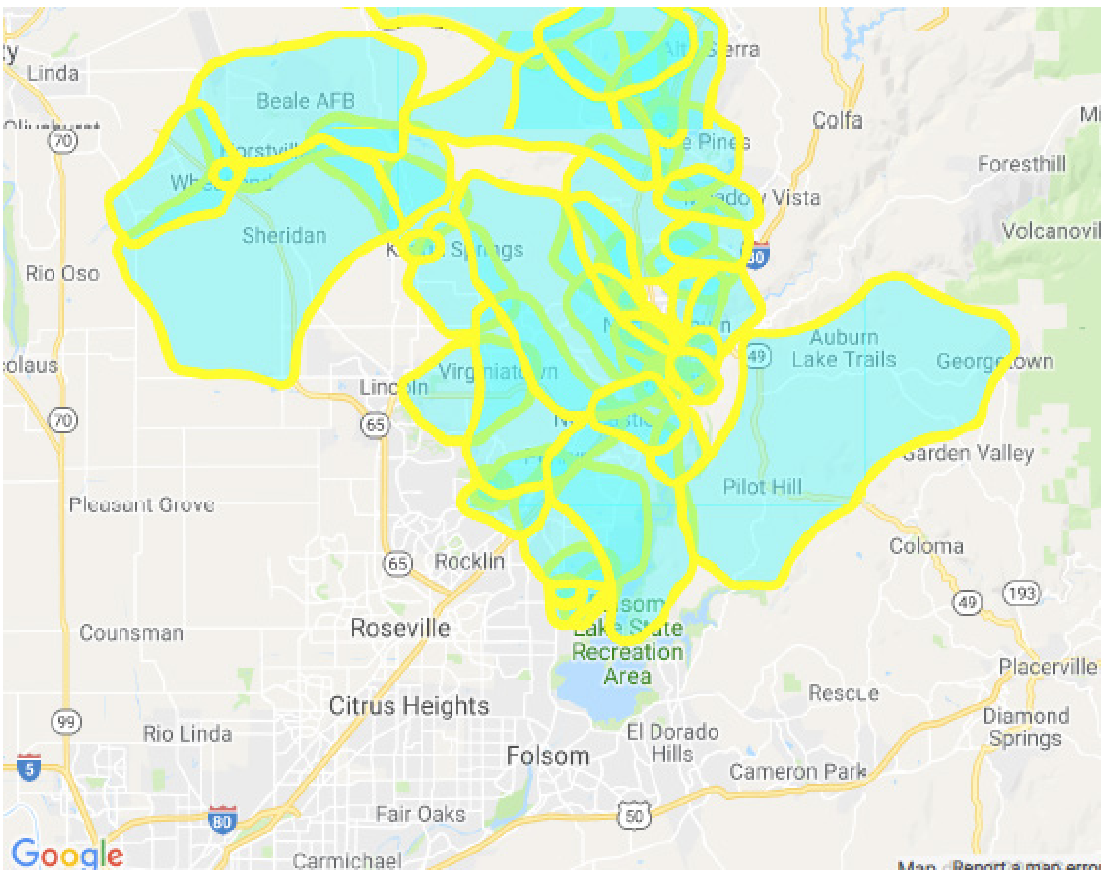
Issue 7*: *Type of Information Provided and Notifications for PSPS Events

CalCCA members have had varied experiences with IOU information dissemination during PSPS events, but generally note that communication needs improvement. Many parties expressed frustration with the inadequate depth and breadth of communication around PSPS events. The recent PG&E September 23-25, 2019 PSPS event (the "September Event") illustrated many of these issues.

41 *See* WSPA Comments at 8.

Generally, IOUs should provide more clear, timely, and complete information to a broader swath of individuals and entities, provide unique information to at-risk populations, and consult with local communities on placement of CRCs. For example, during the September Event, CCAs received notice that the power had already been or would be shut off, but they were given neither a precise time nor exact location. CCAs received customer lists, but did not receive critical information, like the load, latitude/longitude, maps and targeted circuits beyond the immediate meter. In PG&E's territory during this PSPS event, the use of polygons for information reflected 100 feet around the circuit connection.

Image 1: Public map of September PSPS Event in Placer County[42]



These polygons overlapped, causing some areas that were completely surrounded by PSPS shutdowns to appear unaffected by the PSPS event. When pressed for clarity, PG&E indicated that areas islanded in such a manner were likely to lose power. PG&E also advised that checking specific

[42] The overlapping polygons indicate areas likely to be shut off. The impacted area has an island in the center that appears to be unaffected. Clarification from the IOU indicated that the area would most likely be affected though customers in the island area were not contacted.

addresses on the website would provide the best information. Notifications for the September Event began 48 hours ahead of time. The emails for PG&E territory on the September Event read:

> This courtesy notice is for government officials. To protect public safety, PG&E has turned off or will soon turn off power in portions of Butte, Napa, Nevada, Placer, Plumas, Sonoma and Yuba counties. We have been reaching out to customers asking that they prepare emergency plans and supplies.
>
> Power will remain off until weather conditions improve and it is safe to restore service. Outages could last for multiple days. Maps of impacted areas are available at pge.com/pspseventmaps**.** We will continue to keep you updated.

From experience with previous PSPS events, one of the CCAs impacted by this event, Pioneer Community Energy ("Pioneer") knew to access its secure portal for information. Pioneer had customer lists only. While the area on the map had been identified for shutoff, Pioneer received information for customers West of Interstate 80 with no addresses for customers East of Interstate 80. The event was then called off, but Pioneer received a list for individuals on the East of Interstate 80 – customers that had only been identified by the map but were not included on the affected customers list. This conflicting notification is problematic for CCAs trying to prudently manage generation activities and support the safety of their communities.

CalCCA also agrees with the Joint Local Governments on the need to consult with local governments on the placement of Community Resource Centers ("CRCs"). [43] The Joint Local Governments illustrate how the IOUs have been participating in negotiations to secure CRC locations far in advance of actual PSPS events, but unfortunately, some of these places are inadequate. The Joint Local Governments advocate for the Commission to direct the IOUs to work with local governments to identify facilities and locations best suited for CRCs.[44] Local governments would like better consultation on the placement of the CRCs to ensure the best service and access to the individuals needing CRC services. The Joint Local Governments recommend setting a standard for the number of CRCs based upon population, such as 1 per 5,000 residents.[45] CalCCA notes that the concept merits consideration. However, in rural areas, the populations may be so spread out that the number of CRCs may need to be increased due to distance and accessibility.

[43] Joint Local Governments Proposal at 32.
[44] Pioneer conversation with partner local governments.
[45] *See id.* at 33.

Both PG&E and SCE note that they conduct power flow studies prior to PSPS events. PG&E also states that it provides the information to CAISO for power flow studies and that it also contacts transmission level customers.[46] This information should be shared with CCAs and other load-serving entities ("LSEs") to understand the potential impacts to their customers and operations. CMUA supports the IOUs providing advance notice to LSEs and challenges PG&E's allegation that it cannot share load data and circuit information with market competitors.[47] CMUA points out that PG&E has not made its case for labeling municipalities and CCAs being market competitors. [48] CCAs are not market competitors for transmission and distribution service, and actually rely on IOUs to deliver generation service to unbundled customers. The IOUs have an obligation to share relevant transmission and distribution service information that impacts CCAs programs.

Also, CalCCA supports RCRC's recommendation[49] that IOUs should notify adjacent jurisdictions to account for possible movement of individuals from one area to another in search of power and refuge. RCRC also encourages the Commission seek a declaration from the Governor that PSPS events are an emergency due to their potential significant impacts.[50] CalCCA supports the use of emergency powers to support communities facing multi-day power outages.

In addition to more accurate notifications, the IOUs—as the Joint Local Governments comment—should provide greater specificity and granularity in their definitions and designations of impacted areas. CalCCA would like to see historical load information for each circuit that will be deenergized, based upon the specific calendar days for the PSPS event, including: (1) estimated load for each circuit to be deenergized during the PSPS period, and (2) load forecast for medical baseline and critical facilities customers to help discern backup generation needs during a PSPS event. The Joint Communications Parties would like the IOUs to provide geographic information.[51] EPUC requests communications to address the likelihood that a line would be de-energized, and requests that this information be posted to the secure portal. CalCCA agrees that knowing the likelihood of a line outage is useful information.

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46 *See* PG&E's Opening Comments on Phase Ruling at 7.
47 *See* CMUA Comments at 4.
48 *See id.* at 4.
49 *See* RCRC Comments at 8.
50 *See id.* at 9.
51 *See* Joint Communications Parties Comments at 5.

IV. CONCLUSION

CalCCA appreciates the opportunity to provide comments on the proposals to the Commission.

Respectfully Submitted,

/s/ Irene Moosen

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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Examine Electric Utility De-Energization of Power Lines in Dangerous Conditions	Rulemaking 18-12-005 (Filed December 13, 2018)

CALIFORNIA COMMUNITY CHOICE ASSOCIATION RESPONSES TO COMMENTS AND PROPOSALS FILED ON SEPTEMBER 17, 2019

CALCCA
ADVANCING LOCAL ENERGY CHOICE

October 15, 2019

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Table of Contents

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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CALIFORNIA COMMUNITY CHOICE ASSOCIATION RESPONSES TO COMMENTS AND PROPOSALS FILED ON SEPTEMBER 17, 2019

I. INTRODUCTION

The California Community Choice Association ("CalCCA"), the trade association representing Community Choice Aggregators ("CCAs"), appreciates the opportunity to submit the following responses to comments and proposals submitted by parties on September 17, 2019 in response to the *Assigned Commissioner's Phase 2 Scoping Memo and Ruling* issued August 14, 2019 ("Phase 2 Ruling"). CalCCA was granted party status in this proceeding via email ruling on June 17, 2019.

II. BACKGROUND

In the Phase 2 Ruling, the Commission requested that the Investor Owned Utilities ("IOUs") [1] specifically, and other parties as interested, provide proposals in response to several questions. CalCCA notes Decision ("D.") 19-05-042 directed that Phase 2 of this proceeding would consider issues that were outside the scope of Phase 1. Therefore, the Commission may find that the timeline established in the Phase 2 Ruling may need further adjusting to accommodate robust and adequate discussion of many of the suggestions, insights, and comments provided by the parties in their proposals. In the instant Rulemaking, the Commission is considering issues with very significant implications for the health, safety, and well-being of the public. Robust discussion of these issues is essential. While some issues require expedited resolution, for the most part, consideration of these issues should not be rushed. CalCCA reviewed all of the proposals and comments and generally

[1] San Diego Gas & Electric ("SDG&E"), Southern California Edison ("SCE"), and Pacific Gas & Electric ("PG&E") collectively referred to as the IOUs.

distilled them into seven primary issues. On each of those issues, CalCCA has identified areas of agreement and disagreement, issues that should be addressed in a workshop setting and issues that ought to be addressed in new tracks of this proceeding.

III. COMMENTS ON PROPOSALS

***Issue 1*: Definitions And Standard Nomenclature**

Critical Facilities And Infrastructure

CalCCA believes the variety of recommendations indicates the need for a stakeholder workshop to reach consensus on the nomenclature. Several parties proposed reasonable additions to the definition of Critical Facilities and Infrastructure ("CFI"). In addition to the facilities and infrastructure identified in CalCCA's proposal, CalCCA supports the following specific additions to the definition of CFI proposed in parties' comments:

- Facilities that have been designated by a local government entity as a staging site or shelter site.[2]
- Transportation facilities identified by the Commission in D.02-04-060, including navigation communication, traffic control, and landing and departure facilities for air and sea operations" and "rail rapid transit systems as necessary to protect public safety."[3]
- All primary, secondary, and post-secondary schools, including directly affiliated administrative facilities.[4]
- CalTrans facilities.[5]

In addition, CalCCA agrees with the Western States Petroleum Association ("WSPA") that petroleum-related facilities other than refineries should be included in the definition of CFI. However, CalCCA disagrees with WSPA's position that such facilities should be treated as CFI because of their economic importance. By definition, a Public Safety Power Shutoff ("PSPS") event

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2 *See* Rural County Representatives of California ("RCRC") Comments at 3. All further references and citations to "Comments" refer to Parties' September 17, 2019 Comments and Proposals in the instant Rulemaking unless otherwise noted.

3 City and County of San Francisco ("San Francisco") Comments at 3.

4 *See* Direct Acccess Customer Coalition ("DACC") Comments at 2.

5 *See* Terjung and Naylor Comments at 4-5.

has the potential to freeze or substantially limit economic output in the affected area. While it is true that the petroleum industry is a key economic sector for California and the nation as a whole, the same can be said for other essential economic sectors such as mining, agriculture, and manufacturing. However, it clear that not all farms, mines, and factories qualify as CFI. Petroleum-related facilities should only qualify as CFI to the extent that they deal with toxic, explosive, and flammable chemicals that could pose a risk to public safety if the facility loses electricity.[6]

A small number of parties opposed expanding the definition of CFI beyond the definition adopted in Phase 1,[7] and one party, SDG&E, argued that the current definition of CFI is "overly broad" and should be narrowed and aligned with definitions used by other state agencies.[8] These parties' arguments are fundamentally flawed, as they ignore the distinct purpose served by developing a definition of CFI that is specific to the PSPS context. Other agencies have defined CFI in the context of other specific threats, such as wildfires and terrorism. In the PSPS context, "CFI" consists of those facilities and infrastructure that rely on electricity, provide essential public health and safety functions or public services, and would experience significant disruption of their ability to provide these services if electric power were interrupted. A detailed, specific, and comprehensive definition of CFI and list of the facilities and infrastructure that qualify as CFI are essential to fulfilling the following basic PSPS response functions:

1. Identifying all CFI operators that need to be included in the IOUs' mandatory lists of primary and secondary 24/7 emergency contacts.
2. Ensuring that CFI operators receive priority notification (with documented confirmation) of PSPS events.
3. Identifying CFI that has the greatest need for PSPS resiliency resource funds.

6 However, CalCCA believes that the potential economic impact of PSPS, including the potential economic impact on the petroleum sector and secondary impacts on consumers and the economy as a whole from interrupted operations of petroleum facilities, should be considered by the IOUs in deciding whether to de-energize a particular line or lines during a PSPS event.

7 *See*, *e.g.*, California Association of Small and Multi-Jurisdictional Utilities ("CASMU") Comments at 4.

8 *See* SDG&E Comments at 2.

4. Ensuring that all facilities that are essential to public health and safety or that provide critical public services have their backup generation needs assessed by the IOUs, and ensure IOU pre-approval for IOU-provided backup generation.[9]

Under SDG&E's proposal, a range of facilities that are critical for public health and safety would be removed from the definition of CFI. For instance, SDG&E's proposed definition would exclude 911 call centers, hospice care facilities, residential mental health facilities, and a significant number of other facilities and infrastructure that, in a PSPS event, is required to maintain public health, safety, and the provision of essential services.

A number of parties identified facilities and infrastructure that serve an important public function but are not currently included as an *essential* public service. For instance, libraries and post offices do not provide an essential public service of immediate and urgent need (unless a given library or post office has been designated as an emergency shelter or staging site). Similarly, CalCCA does not support the elevation of electric vehicle ("EV") chargers to critical infrastructure as proposed by the California Energy Storage Alliance ("CESA"),[10] since chargers and charging stations serve the same function as gas stations (providing fuel for vehicles), which are not currently considered critical facilities. During a PSPS event, fueling any vehicle (electricity or fossil fuel dependent) is likely to present a similar challenge of inability to "load" the vehicle (i.e., recharge or refuel).

PSPS Phase Nomenclature

CalCCA asks that when the Commission considers terms used for pre-, during, and post-PSPS, those terms be consistent, simple, understandable, and easy to translate into multiple languages. The PSPS terms should also be differentiated enough from disaster response terminology to avoid confusion or conflict with other statutes and regulations. Various parties have proposed differing PSPS terminology: PG&E proposes a nomenclature for the various stages of a PSPS event;[11] multiple parties provided variations of language for PSPS Phase names; and Mr. Abrams proposed replicating federal designations for event stages, including preparedness, response,

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9 *See*, D.19-05-042 at 73-74 ("the utilities must assist critical facility and infrastructure customers to evaluate their needs for backup generation and determine if additional equipment is needed, potentially including utility-provided generators for facilities that are not well prepared for a power shut-off")

10 *See* CESA Comments at 2.

11 *See* PG&E Opening Comments on Phase 2 Ruling at 3.

recovery, and mitigation.[12] Through a workshop, the Commission could ascertain appropriate terms for PSPS phases from stakeholders themselves. CalCCA also suggests that terms be adopted to distinguish between possible, planned, and (actual) ongoing PSPS events.

<u>Issue 2</u>*: *Vulnerable Customers / Increased Risk Individuals

The majority of parties that commented on the Medical Baseline issue agreed that the current Commission Rules and IOU practices for identifying and enrolling all eligible Medical Baseline Customers are inadequate and must be improved. SCE and SDG&E offered general acknowledgements that the Commission should refine the approach for Medical Baseline customers. Both the Joint Local Governments and San Francisco stress the importance of requiring that the IOUs work with local jurisdictions to identify and enroll eligible Medical Baseline customers.[13] The Utility Reform Network ("TURN") identifies Medical Baseline under-enrollment as an urgent problem, stating that "the profound underutilization of the Medical Baseline program should be addressed quickly and efficiently as possible."[14]

CalCCA strongly agrees that the IOUs should be required to significantly improve their practices for identifying and enrolling Medical Baseline customers, with a goal of 100% enrollment of all eligible customers. CalCCA further agrees that the IOUs should be required to coordinate closely with local jurisdictions to improve Medical Baseline enrollment.

Similarly, a number of parties noted the importance of identifying and taking steps to protect Access and Functional Needs ("AFN") customers. The Center for Accessible Technology ("CforAT") argued that the Commission should focus on methods outside the Medical Baseline designation to identify AFN customers and ensure that they are not put at risk during a de-energization event.[15] San Francisco argued that the Commission should require that the IOUs develop and regularly update lists of AFN persons, and provide targeted outreach to vulnerable populations by entering into data sharing agreements with agencies that provide services to AFN persons. CalCCA strongly agrees that AFN persons are at a substantially increased risk of harm during a PSPS event and that the IOUs are responsible for whatever steps are necessary to mitigate

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12 *See* Comments of William B. Abrams at 6.
13 *See* San Francisco Comments at 4.
14 TURN Comments at 3.
15 *See* CforAT Comments at 6.

this harm, including maintaining lists of AFN individuals, data-sharing with appropriate agencies, and targeted outreach.

However, as CalCCA noted in its Proposal, it is essential that the IOUs identify *all residents that are at a substantially increased risk of harm during a PSPS event*. Medical Baseline customers are one subset of a broader group of Increased Risk Individuals ("IRIs"), and AFN persons are another subset of IRIs. However, there are many IRIs that may not qualify for or be enrolled in the Medical Baseline program and do not meet the definition of AFN. Thus, while CalCCA supports requirements and program changes aimed at significantly increasing Medical Baseline enrollment, and proposed steps to improve protections for AFN persons, these alone may only partially address the need, leaving many vulnerable individuals that must be identified through other means. As noted by the City of San José, medical baseline tariffs are one way to identify individuals who need assistance during a PSPS event, but they are merely an economic billing program."[16] An IOU's list of Medical Baseline customers is not a comprehensive list of all individuals at an increased risk of harm due to a PSPS event. [17] As San José further notes:

> The program is not well-known and relies on individuals with enough knowledge to sign up for the special electrical rates/fees. But not everyone who requires electricity for life-supporting services (e.g., using a ventilator) will have signed up for this program and could therefore be missed during a PSPS." [18]

Identifying *all* IRIs is essential to mitigating the worst potential harms of PSPS outages. A complete list of IRIs, along with some kind of risk categorization, is essential for the utilities to (1) target priority notification (with documented confirmation); (2) notify authorities of customers at immediate, life-threatening risk during an outage (such as customers on electrically powered life-support equipment); and (3) identify the customers with the greatest need for resiliency resources.

CalCCA recognizes that identifying all IRIs is a large task that raises a number of policy, legal, and practical issues.[19] CalCCA proposes that the Commission initiate a separate, dedicated

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[16] Comments of the City of San Jose at 4.

[17] CalCCA Comments at 12.

[18] *Id.* at 4.

[19] CforAT Comments at 3 (noting that utilities might not be the best place to concentrate AFNs information and that the IOUs must take additional steps year-round to acclimate AFNs to PSPS events and to raise awareness of data sharing needs for AFNs populations. CforAT observed that low income AFNs or households without transportation may not have the listed means of communication that IOUs employ for notifying PSPS affected individuals.). CforAT also acknowledges that communication with AFNs requires special approaches beyond the standard established communication methods already established, at 9.

track of the instant Rulemaking focused on PSPS rules to protect Vulnerable Populations / IRIs. This track would include the consideration of PSPS-related issues as they apply to Medical Baseline, AFN, and all other IRIs, and should, at a minimum, address the following questions:

- Definition of IRIs (in addition to Medical Baseline and AFN customers):
    - What other groups should be included in the definition of IRIs?
    - Should IRIs be divided into "tiers" or otherwise categorized according to likelihood and potential severity of harm in a PSPS event? If so, how should these tiers be defined?
- How should the IOUs identify and track IRIs?
- What Commission oversight is required to ensure that the IOUs are adequately identifying IRIs and maintaining current contact information?
- What privacy protections or modifications to existing privacy rules are necessary to protect IRIs?
- What steps should the IOUs be required to take to ensure that IRIs have access to resiliency resources?

Some parties proposed that any matters relating to the Medical Baseline program be separated from this proceeding. CalCCA strongly opposes this proposal. Medical Baseline customers (and other IRIs) face a unique set of risks due to PSPS events, and mitigating these risks requires a set of IOU actions and requirements that are distinct to the PSPS context. Separating the Medical Baseline issue further risks creating a serious disconnect between inter-dependent issues, due to a separate record being developed and risks limiting participation of parties and misalignment with the progress in Phase II of this proceeding.

As part of this proposed Vulnerable Populations / IRIs track, CalCCA recommends that the Commission hold a at least one workshop with community-based organizations and local governments that have experience in communicating to AFN populations to identify further steps to take**.**

<u>Issue 3</u>*: *Transmission and Distribution

CalCCA agrees with PG&E that the Commission should establish clear, standard definitions for "transmission level PSPS" and "distribution-level PSPS."[20] However, CalCCA differs from

[20] PG&E Comments at 3.

PG&E in believing that it is essential that the Commission adopt a single standard definition for all IOUs. The definitions adopted by the Commission will affect communications and notifications, as well as designation of "transmission level" customers, and should be as clear and straightforward as possible. As is apparent from SCE and PG&E's comments,[21] the distinction between so-called "sub-transmission" and "distribution" lines is functional, depending on an electric system's design, and the voltage level that distinguishes between "sub-transmission" and "distribution" differs significantly between the IOUs. Rather than adopting separate definitions of "distribution" and "transmission" for each IOU to reflect this difference – an option which would almost certainly lead to significant confusion – CalCCA supports the Energy Producers and Users Coalition ("EPUC") proposal that the Commission adopt a single set of baseline definitions based on California Independent System Operator ("CAISO") control. "Transmission" lines and facilities would be those that have been transferred to CAISO control, and "distribution" lines and facilities would be those that remain fully under the control of the IOUs.[22] CalCCA agrees with the California Municipal Utilities Association ("CMUA") that clarification on this matter is necessary,[23] and proposes that the Commission hold workshops to clarify this baseline definition and determine if any further actions need to be taken to ensure compliance with CAISO rules and other regulatory requirements.

CalCCA is concerned by PG&E's statement that further clarity from the Commission on this topic is necessary "since the notification process and Federal Energy Regulatory Commission standards of conduct, for example, are different for transmission events than for distribution events."[24] This statement is very troubling, and implies that PG&E may be intending to withhold advance notice of transmission-related PSPS events to certain Public Safety Partners. CCAs need access to PSPS transmission-related information to modify their power scheduling to match the reduction in load due to the outage *as required by CAISO rules*. The Commission should clearly direct the IOUs to provide transmission-related PSPS information to all Public Safety Partners.

***__Issue 4__*: Public Safety Partner Access To PSPS Information**

CalCCA recommends the Commission initiate a new track in this proceeding to address concerns regarding access to confidential customer data. First Responders and Public Safety Partners

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21 *See* SCE Comments at 2-3; PG&E Comments at 3.
22 *See* EPUC Comments at 5-6.
23 *See* EPUC Comments at 5-6
24 PG&E Comments at 3.

need to access necessary data in advance of, and during, PSPS events to prepare response plans, evacuation and transportation plans, and resiliency center location evaluations. PG&E has limited access to this information by demanding that Public Safety Partners, including CCAs, execute overbroad and burdensome non-disclosure agreements ("NDAs"). These NDAs have been neither reviewed nor approved by the Commission, and would be enforced by PG&E, not the Commission. These NDAs reduce the ability of emergency responders and local governments to ensure public safety. CCAs have a broad right to relevant customer information, and are subject to the Commission's customer privacy rules, rendering any NDA requirement duplicative and unnecessary.[25] Other first responders and local government units are not similarly situated. As the Joint Local Governments point out, the IOUs' requirement that local governments sign unreasonably restrictive IOU-imposed NDAs might delay the dispatching of third-party resources like ambulances. The Commission explicitly recognized the information-sharing problems created by PG&E's NDA in President Batjer's October 14, 2019 Letter to PG&E. In this letter, President Batjer directed PG&E to take a range of immediate corrective actions, including:

> Develop processes and procedures for sharing information of medical baseline customers that can be impacted by a specific PSPS event…. the utilities are expected to share medical baseline information with counties and tribal governments, if requested, without a memorandum of understanding or non-disclosure agreement during PSPS events.[26]

The letter further directed PG&E to:

> Develop processes and procedures for sharing information on critical facilities with counties and local governments during events. This must include a solution for sharing information with counties and local governments even if there is no existing memorandum of understanding or non-disclosure agreement.[27]

CalCCA strongly agrees with these directives, and asks that the Commission explicitly extend them to CCAs, clarify that these directives apply to information both during and prior to PSPS events, and incorporate them into the PSPS Rules.

The Joint Local Governments note that the federal Health Insurance Portability and Accountability Act of 1996 ("HIPPA") establishes a framework that respects an individual's privacy while addressing the need for multiple parties to access the requisite information to provide medical care; it allows for sharing an individual's information without obtaining consent in each instance, and

25 *See*, generally, D.12-08-045 (adopting customer information confidentiality rules for CCAs).
26 At 4-5.
27 *Id.* at 5.

in turn binds those who receive the information from disclosure. [28] CalCCA further with the Joint Local Governments that the Commission needs to take up the topic of confidential customer data and make it a priority. The Commission should ultimately adopt a single set of PSPS privacy and confidentiality rules that applies to all IOUs and Public Safety Partners to address the issues of medical baseline customers, rules on confidentiality, and AFNs needs as discussed in Issue 4, below. AFNs need improved and expanded communication. These are complex issues that merit a careful policy analysis that balances the needs of Public Safety Partners with personal or confidential information in order to avoid life-threatening situations and provide essential services with a variety of privacy and confidentiality considerations.

To address these complex issues, CalCCA requests that the Commission open an additional track in this Rulemaking to address the public safety and customer privacy implications of PSPS information-sharing with Public Safety Partners. The goals of this track should be to:

- Develop a single standardized NDA, or set of customer information privacy rules, for non-CCA Public Safety Partners that:
    - Does not impose unreasonable or burdensome terms on Public Safety Partners.
    - Allows adequate flexibility to share confidential information when necessary to protect life and property.
    - Is overseen and enforced by the Commission, not the IOUs.
- Consider any changes to existing IOU and CCA customer privacy rules that are needed for the PSPS context.

Because adequate information sharing is essential to protecting public safety, CalCCA asks that this proposed track be expedited.

***Issue 5*: Establishing Standardized PSPS Criteria**

Most of the parties that commented on Standardized PSPS Criteria agreed that some flexibility is necessary to allow the IOUs to account for regional variation and opposed the fixing of *absolute* criteria for PSPS. CalCCA agrees with these parties that, as a general matter, absolute criteria do not allow for the flexibility necessary to address differences between IOU territories, line states, vegetation, geography, and other factors. At the same time, CalCCA strongly supports the adoption of a "floor" for the IOUs – a minimum set of criteria that an IOU must consider, and

[28] *See* Joint Local Governments' Comments at 12.

analysis that the IOU must conduct, before initiating a PSPS event. This minimum analysis should consist of a balancing test that balances, on one hand, the likelihood and potential extent of harm from not deenergizing (measured as likelihood of ignition and the probability of the fire spreading), and, on the other hand, the likelihood and extent of harm caused by the PSPS. In its Proposal CalCCA provided a specific list of minimum criteria that should be considered by IOUs in this balancing test.[29] CalCCA urges the Commission to make the tracking, quantification or measurement (where appropriate), and consideration of each of these minimum criteria as mandatory for each IOU. Each IOU should be allowed to account for regional variation by assigning different weighting to the mandatory minimum criteria, or by including additional, region-specific criteria to its analysis.

A mandatory minimum set of criteria and balancing test methodology is needed to reduce disparities among IOUs. The Commission should hold a workshop on this topic. The Mussey Grade Road Alliance ("MGRA"),[30] for example, noted that from June 2019 to September 2019:

> SCE has issued 6 de-energization reports, PG&E has issued 1 de-energization report, and SDG&E and the small IOUs have issued none. The disparity between these numbers indicates that there may be a major difference in approach to shutoff criteria between the major utilities. [31]

MGRA further notes that the Commission should be concerned that SCE is on the verge of shutoffs so often.[32] The disparity may indicate that a standard set of criteria is warranted. The City of San Jose argues that criteria are necessary.[33]

Several parties opposed or expressed caution towards any level of standardized criteria. PG&E notes that while standardized criteria are appealing, there are variations among the IOU territories, that may work against standardization. The CASMU supports a non-standardized criterion that is process reflective, rather than fixed, explaining:

> Best practices or applicable criteria for assessing wildfire risk and/or de-energization events will vary for different utilities. Many tools used to assess and analyze landscapes or fire conditions are resource dependent. Small utilities, like the CASMU members, will not have the same resources or the same tools as the Large IOUs.[34]

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29 CalCCA Proposal at 15-18.

30 MGRA Comments at 7.

31 *Id.* at 9.

32 *Id.*

33 *See* Comments of the City of San Jose at 11.

34 Proposal of Bear Valley Electric Service (U 913 E), A Division of Golden State Water Company, Liberty Utilities (CalPECO Electric) LLC (U 933 E), and PacificCorp (U901 E) at 9.

The Public Advocates Office cautions the Commission against setting criteria that create rigid thresholds that could impair flexibility or incentivize adverse actions.[35] EPUC agrees the statewide criteria is useful but believes defining risk criteria by the service territory might better serve customers.[36] WSPA concurs that some criteria are needed, but warns that prescriptive criteria could be problematic for certain service areas based upon the terrain and electric wire conditions.[37]

These concerns are adequately addressed by CalCCA's proposal to allow regional variation in the weighting of mandatory minimum criteria and the consideration of additional criteria. Although most of the minimum criteria proposed by CalCCA consist of information all utilities should already have (i.e. records of line maintenance, pole type, conductor type, time since last brush clearing, etc.) a small handful of CalCCA's proposed criteria are somewhat resource dependent. For instance, vegetation moisture measurements may require the use of drone and satellite resources that some IOUs do not currently have in place. The Commission should reasonably accommodate the IOUs' starting points and allow for some degree of phase-in in establishing mandatory minimum criteria.

CalCCA agrees with the Joint Local Governments that the Commission should require that the IOUs' not only document the conditions the IOU used to evaluate the PSPS event, but also a transparent disclosure of the decision process, measured steps taken, and any additional variables the IOU used to determine whether or not to call a PSPS event.[38] If these details are incorporated, the Commission could use this information to establish standards to balance the potential safety benefits to be gained from PSPS against the potential harms caused by PSPS.

As a component of the risk assessment, WSPA recommends that the Commission call for a study and cost-benefit analysis of shutoffs, similar to the models used in the insurance industry.[39] The Utility Consumers Action Network ("UCAN") concurs, noting:

> Shutoff thresholds should be optimized through a risk/benefit or cost/benefit analysis and that remediation plans be put in place to strengthen infrastructure over time and raise shutoff thresholds. In particular, UCAN supports the suggestion that "in order for a utility to assert that it has used shut-off as a 'last resort,' it needs to demonstrate that it has clearly quantified the risks introduced by shutoff and showed them to be lesser than those of leaving lines energized.[40]

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35 *See* Proposal of the Public Advocates Office at 3.
36 *See* EPUC Comments at 10.
37 *See* Comments of WSPA at 7.
38 *See* Joint Local Governments' Comments at 18.
39 *See* WSPA Comments at 8.
40 UCAN Comments at 5.

If the Commission decides to consider a cost-benefit risk analysis, CalCCA recommends a workshop to allow stakeholders the opportunity participate the development of the methodology for making these calculations. Finally, CalCCA agrees with WSPA that the Commission should clarify that the IOUs are not immune to claims for consequential PSPS damages and liabilities caused by a PSPS event.[41] The questions of what those costs would be and how they would be allocated merits another track in this proceeding.

<u>Issue 6</u>: The Role of CCAs in PSPS

All the IOUs and several other parties agree that CCA notification responsibility with respect to a PSPS event is limited to acting in a supporting role. As SCE states, CCAs should not be primarily responsible for communication of PSPS events. Only the Small Business Utility Advocates ("SBUA") recommend that the CCAs should be required to communicate directly with customers regarding impending PSPS events. While CalCCA appreciates SBUA's acknowledgment of the relationships CCAs develop with their local commercial and industrial customers, the IOUs—as the grid operators and the ultimate PSPS decisionmakers—are in the best position to serve in the primary communication role. CCAs lack the immediate access to the necessary information to adequately and accurately serve as the front lines of communications about PSPS events. CalCCA generally agrees with the IOUs that state the CCAs should refer questions about PSPS events to the IOU which delivers the power in their respective areas consistent with PG&E's and SCE's Electric Rule No. 23 C5(a) and SDG&E's Electric Rule 27.

CalCCA is open to discussion about how CCA roles may change in preparation for PSPS events in the future. The comments here regarding the role of CCAs in PSPS focus on notification and communication. The CCAs could also play important roles in raising PSPS awareness and developing PSPS mitigation measures, such as micro-grids.

<u>Issue 7</u>: Type of Information Provided and Notifications for PSPS Events

CalCCA members have had varied experiences with IOU information dissemination during PSPS events, but generally note that communication needs improvement. Many parties expressed frustration with the inadequate depth and breadth of communication around PSPS events. The recent PG&E September 23-25, 2019 PSPS event (the "September Event") illustrated many of these issues.

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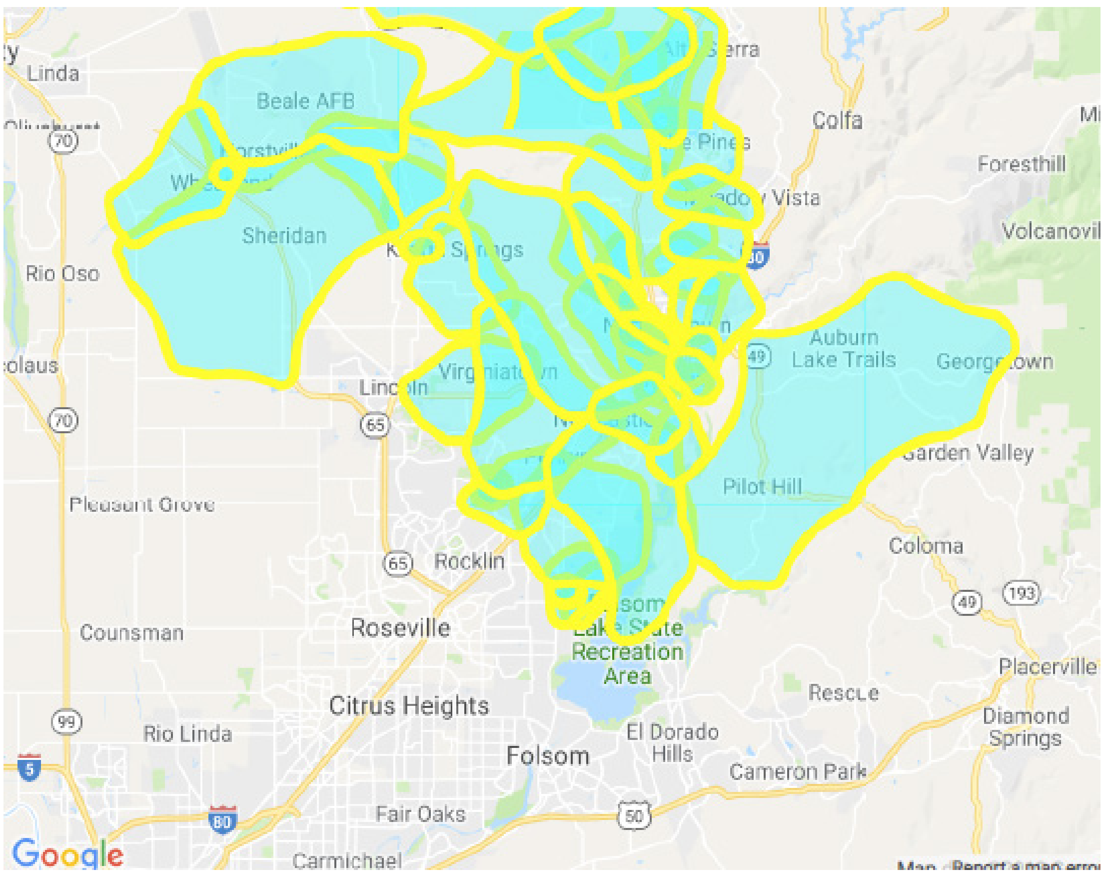
41 *See* WSPA Comments at 8.

Generally, IOUs should provide more clear, timely, and complete information to a broader swath of individuals and entities, provide unique information to at-risk populations, and consult with local communities on placement of CRCs. For example, during the September Event, CCAs received notice that the power had already been or would be shut off, but they were given neither a precise time nor exact location. CCAs received customer lists, but did not receive critical information, like the load, latitude/longitude, maps and targeted circuits beyond the immediate meter. In PG&E's territory during this PSPS event, the use of polygons for information reflected 100 feet around the circuit connection.

Image 1: Public map of September PSPS Event in Placer County[42]



These polygons overlapped, causing some areas that were completely surrounded by PSPS shutdowns to appear unaffected by the PSPS event. When pressed for clarity, PG&E indicated that areas islanded in such a manner were likely to lose power. PG&E also advised that checking specific

[42] The overlapping polygons indicate areas likely to be shut off. The impacted area has an island in the center that appears to be unaffected. Clarification from the IOU indicated that the area would most likely be affected though customers in the island area were not contacted.

addresses on the website would provide the best information. Notifications for the September Event began 48 hours ahead of time. The emails for PG&E territory on the September Event read:

> This courtesy notice is for government officials. To protect public safety, PG&E has turned off or will soon turn off power in portions of Butte, Napa, Nevada, Placer, Plumas, Sonoma and Yuba counties. We have been reaching out to customers asking that they prepare emergency plans and supplies.
>
> Power will remain off until weather conditions improve and it is safe to restore service. Outages could last for multiple days. Maps of impacted areas are available at pge.com/pspseventmaps**.** We will continue to keep you updated.

From experience with previous PSPS events, one of the CCAs impacted by this event, Pioneer Community Energy ("Pioneer") knew to access its secure portal for information. Pioneer had customer lists only. While the area on the map had been identified for shutoff, Pioneer received information for customers West of Interstate 80 with no addresses for customers East of Interstate 80. The event was then called off, but Pioneer received a list for individuals on the East of Interstate 80 – customers that had only been identified by the map but were not included on the affected customers list. This conflicting notification is problematic for CCAs trying to prudently manage generation activities and support the safety of their communities.

CalCCA also agrees with the Joint Local Governments on the need to consult with local governments on the placement of Community Resource Centers ("CRCs"). [43] The Joint Local Governments illustrate how the IOUs have been participating in negotiations to secure CRC locations far in advance of actual PSPS events, but unfortunately, some of these places are inadequate. The Joint Local Governments advocate for the Commission to direct the IOUs to work with local governments to identify facilities and locations best suited for CRCs.[44] Local governments would like better consultation on the placement of the CRCs to ensure the best service and access to the individuals needing CRC services. The Joint Local Governments recommend setting a standard for the number of CRCs based upon population, such as 1 per 5,000 residents.[45] CalCCA notes that the concept merits consideration. However, in rural areas, the populations may be so spread out that the number of CRCs may need to be increased due to distance and accessibility.

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43 Joint Local Governments Proposal at 32.

44 Pioneer conversation with partner local governments.

45 *See id.* at 33.

Both PG&E and SCE note that they conduct power flow studies prior to PSPS events. PG&E also states that it provides the information to CAISO for power flow studies and that it also contacts transmission level customers.[46] This information should be shared with CCAs and other load-serving entities ("LSEs") to understand the potential impacts to their customers and operations. CMUA supports the IOUs providing advance notice to LSEs and challenges PG&E's allegation that it cannot share load data and circuit information with market competitors.[47] CMUA points out that PG&E has not made its case for labeling municipalities and CCAs being market competitors. [48] CCAs are not market competitors for transmission and distribution service, and actually rely on IOUs to deliver generation service to unbundled customers. The IOUs have an obligation to share relevant transmission and distribution service information that impacts CCAs programs.

Also, CalCCA supports RCRC's recommendation[49] that IOUs should notify adjacent jurisdictions to account for possible movement of individuals from one area to another in search of power and refuge. RCRC also encourages the Commission seek a declaration from the Governor that PSPS events are an emergency due to their potential significant impacts.[50] CalCCA supports the use of emergency powers to support communities facing multi-day power outages.

In addition to more accurate notifications, the IOUs—as the Joint Local Governments comment—should provide greater specificity and granularity in their definitions and designations of impacted areas. CalCCA would like to see historical load information for each circuit that will be deenergized, based upon the specific calendar days for the PSPS event, including: (1) estimated load for each circuit to be deenergized during the PSPS period, and (2) load forecast for medical baseline and critical facilities customers to help discern backup generation needs during a PSPS event. The Joint Communications Parties would like the IOUs to provide geographic information.[51] EPUC requests communications to address the likelihood that a line would be de-energized, and requests that this information be posted to the secure portal. CalCCA agrees that knowing the likelihood of a line outage is useful information.

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46 *See* PG&E's Opening Comments on Phase Ruling at 7.
47 *See* CMUA Comments at 4.
48 *See id.* at 4.
49 *See* RCRC Comments at 8.
50 *See id.* at 9.
51 *See* Joint Communications Parties Comments at 5.

IV. CONCLUSION

CalCCA appreciates the opportunity to provide comments on the proposals to the Commission.

Respectfully Submitted,

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

Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements.	R.16-02-007 (Filed on February 11, 2016)

COMMENTS OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION IN RESPONSE TO RULING SEEKING COMMENT ON FILING REQUIREMENTS FOR 2020 INTEGRATED RESOURCE PLANS

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TABLE OF CONTENTS

Contents

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COMMENTS OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION IN RESPONSE TO RULING SEEKING COMMENT ON FILING REQUIREMENTS FOR 2020 INTEGRATED RESOURCE PLANS

The California Community Choice Association[1] (CalCCA) submits these comments pursuant to the *Administrative Law Judge's Ruling Seeking Comment on Filing Requirements for 2020 Integrated Resource Plans* (Ruling).

I. INTRODUCTION AND SUMMARY

CalCCA appreciates the opportunity to provide comments in response to the Ruling and the Staff Proposal. CalCCA members are dedicated to working with the Commission and other jurisdictional load-serving entities (LSEs) to ensure that the statewide resource planning process enables California to fulfill its reliability and climate goals. In this vein, CalCCA recommends further informal communication among the Staff and LSEs to understand the complexities Staff encountered in aggregating LSEs' portfolios in the 2017-2018 planning cycle. A shared understanding will allow these stakeholders to balance the Staff's interest in uniformity with the

[1] California Community Choice Association represents the interests of 19 community choice electricity providers in California: Apple Valley Choice Energy, CleanPowerSF, Clean Power Alliance, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Monterey Bay Community Power, Peninsula Clean Energy, Pioneer Community Energy, Pico Rivera Innovative Municipal Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Jacinto Power, San Jose Clean Energy, Silicon Valley Clean Energy, Solana Energy Alliance, Sonoma Clean Power, and Valley Clean Energy.

statutory requirements for local government oversight of Community Choice Aggregator (CCA) procurement. Departing from a point of shared understanding will best ensure a balanced and reasonable outcome.

II. QUESTIONS RELATED TO SECTION 2: GENERAL RULES AND GUIDELINES

A. Question 1: Type of plan

Comment on the proposed changes to the type of plan that LSEs are eligible to file. Are there other changes, or modifications to the proposed changes, that should be considered?

CalCCA urges the Commission to reconsider the Staff's proposal to require all LSEs to file Standard Plans, regardless of the load served by individual LSEs. A few CalCCA members with annual load under 700 gigawatts (GWhs) filed Alternative Plans in the last cycle and request the opportunity to maintain this option.[2]

While these CCAs generally understand the Staff's interest in uniformity to ease of data aggregation and analysis, this proposed change represents a significant increase in regulatory burden on small LSEs. Furthermore, the statute clearly requires only LSEs who serve more than 700 GWhs in annual load to file Integrated Resource Plans (IRPs).[3] Thus, before adopting this requirement, CalCCA, and particularly its members who serve annual loads below the statutory threshold, asks for further clarification of the incremental value to the planning process of requiring small LSEs to provide substantially granular forecasts.

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[2] ALJ Ruling Finalizing Load Forecasts and Greenhouse Gas Benchmarks for Individual Integrated Resources Plan Filings at 4-5.

[3] CAL. PUB. UTIL. CODE § 9621(a).

B. Question 2: Required and Optional Portfolios.

Comment on the proposed changes to the required and optional portfolios for individual LSE filings. Are there changes, or modifications to the proposed changes, that should be considered?

1. The Process Should Aim to Standardize Assumptions to Facilitate Plan Aggregation but Should Not Standardize Portfolios

The Legislature's IRP directives, adopted in Senate Bill (SB) 350, require the Commission to balance the need for a statewide resource coordination with the independent role carved out for CCAs by Assembly Bill (AB) 117. The Commission has expressly recognized the need for this balance, declaring its "respect [for] the separate authority of CCA governing boards and the limitations of our rate and contract authority" over CCAs.[4] It has confirmed that "with some exceptions related to renewable integration resources, the procurement decisions, customer rates, and contract terms and conditions (outside of the RPS) are the domain of the CCA governing boards and not the Commission."[5]

The Commission has also recognized that its authority to adopt procedural requirements for CCA IRPs is "primarily with respect to the [statewide] planning process, in order to assess the aggregated impact of all LSE plans combined."[6] Thus, the purpose of the Commission's authority is to ensure that CCAs provide the Commission with adequate information to fulfill its statewide planning function, not to regulate or direct CCA resource planning and procurement.

Within this scope of authority, the Commission may standardize the manner in which the CCAs *present* their preferred portfolios in the IRP process to enable aggregation of LSE portfolios, but may not attempt to standardize the portfolios themselves. Its qualitative

4 Decision (D.)18-02-018 at 158.
5 *Id*. at 26.
6 *Id*.

assessment of CCA preferred portfolios must be limited to certification that the portfolios conform to the state's statutory procurement mandates.

The Staff's Proposal falls within these boundaries to the extent it specifies the "inputs and assumptions" Staff uses in developing the Reference System Portfolio (RSP) and requires a CCA to identify how it intends to meet the renewable integration requirements identified by the Commission.[7] As noted below, however, even standardizing assumptions presents technical challenges. The Staff's Proposal risks going beyond the Commission's statutory boundaries, however, in two respects. First, by failing to define "integration of renewable energy," the Staff Proposal risks interpreting the statute so broadly that this exception from CCA governing board authority swallows the rule. Second, the Staff proposal sets as a planning standard the requirement that a CCA's plan must account for the "resource mix identified in the optimal portfolio."[8] This requirement encroaches on a CCA governing board's authority to determine the resource mix necessary, within statutory constraints, to meet local governmental mandates and objectives.

a. The Commission Should Define "Renewable Integration"

California Public Utilities Code section 454.51 directs the Commission to "identify a diverse and balanced portfolio of resources needed to ensure a reliable electricity supply that provides optimal integration of renewable energy."[9] It further requires the Commission to permit CCAs to submit proposals to satisfy their share of the "renewable integration need."[10] Decision (D.)18-02-018, despite using the term "renewable integration" more than a dozen times, does not define the term. Moreover, the scope of renewable integration implied in the

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7 Staff Proposal at A-14.
8 *Id.* at A-21.
9 CAL. PUB. UTIL. CODE § 454.51(a)
10 *Id.* at § 454.51(d).

decision comes close to swallowing what was intended by the Legislature to be a specific, limited exception to CCAs' ability to procure the resources of their choosing to meet customer needs. To ensure the IRP process stays within the Commission's scope of authority, CalCCA recommends that at the outset of this planning process the adoption of a specific, limited definition of for the "integration of renewable energy" and "renewable integration need."

A specific, limited definition of "renewable energy integration resources" should focus on those specific grid services needed by the grid operator uniquely and specifically to address the operating characteristics of variable fuel resources. The definitions should recognize that many renewable resources, such as geothermal, small hydro, or solar and wind with smart inverters or storage,[11] self-integrate and can be optimally dispatched. Yet other inflexible resources make integration of variable fuels resources more difficult, such as relatively inflexible nuclear or natural gas resources that cannot respond adequately to variable needs.

The Commission should begin this process with the following definition of renewable integration resources:

> Resources with specific operating characteristics, grid locations, and other attributes that provide, or mitigate the need for, specific grid services that are necessary to accommodate grid needs directly created by variable fuel or intermittent generation.

While the Commission should solicit stakeholder input to build on the work already done by the California Independent System Operator (CAISO), National Renewable Energy Laboratory (NREL) and others to define renewable integration services,[12] the Commission should take as a starting point for the list of services needed by grid operators to include the following:

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[11] *See* NREL (2017) "Demonstration of Essential Reliability Services by a 300-MW Solar Photovoltaic Power Plant," available at https://www.nrel.gov/docs/fy17osti/67799.pdf.

[12] *See, e.g.*, NREL (2015) "Grid Integration and the Carrying Capacity of the U.S. Grid to Incorporate Variable Renewable Energy," available at https://www.nrel.gov/docs/fy15osti/62607.pdf;

(1) Inertial response, primary and secondary frequency control;

(2) Fast response dispatchability to address sub-hourly variability;

(3) Flexible ramping to manage renewable fuel forecast and generation uncertainties;

(4) Daily or seasonal management of overgeneration to maximize value of renewable energy; and,

(5) Other services specifically required by grid operators to address grid needs directly driven by variable fuel reliance. A specific services-based approach would allow all technologies capable of providing one or more such services to participate and qualify as renewable energy integration resources.

Resource integration should *not* be defined, however, as a mandated resource or technology mix —a definition that would eviscerate a CCA's right to deploy a procurement strategy that responds to locate preferences and needs.

b. The Commission Should Not Mandate a CCA's Resource Mix

The Commission should make clear that while CCA portfolios must meet statutory mandates and provide for the CCA's self-procured share of renewable integration resources, CCAs are not otherwise required to propose a portfolio mix that conforms to the Staff's optimal portfolio. Specifically, CCA portfolios may reflect a different, yet still compliant, resource mix more reflective of the CCA's load profile, local preferences, or other directives of the CCA Governing Board. Individual CCAs have different locally mandated renewable and carbon-free procurement targets, local programs that aim at reducing energy consumption and transportation electrification, and varying proportions of residential and commercial loads. Under these circumstances, it is highly challenging for each CCA to provide a portfolio that conforms to the RSP resource mix.

NREL (2018) "Integrating High Levels of Variable Renewable Energy into Electric Power Systems," available at https://www.nrel.gov/docs/fy17osti/68349.pdf.

2. Adhering to the Inputs and Assumptions of the Conforming Portfolio Will Present Technical Challenges

The Staff's Proposal would permit LSEs to produce only Conforming Portfolio(s) using their assigned load forecast.[13] This means that LSE proposals would need to use the 2030 LSE-specific Greenhouse Gas (GHG) Emissions Benchmark, the LSE's assigned load forecast, and other RSP inputs and assumptions.[14] While CalCCA understands the Commission's goals in standardizing inputs and assumptions to enable a consistent aggregated view of planning, in some cases, mandating conformity may not result in the most accurate view.

CCAs employ different planning constraints that may not reflect statewide assumptions. For example, some CCAs have 100 percent carbon-free goals that may push them toward a higher renewable portfolio standard (RPS) and carbon-free content than the RSP. Indeed, the balance between RPS and carbon-free resources may fluctuate over time in response to changing local government preferences. In addition, some CCAs aim to more closely align their demand with supply using demand-side tools and distributed energy resources (DERs). Their forecasts thus may diverge from the statewide planning assumptions relative to the California Energy Commission (CEC) load forecasts, which captures only programs funded by Public Purpose Program (PPP) funds. Likewise, some CCAs have more ambitious transportation electrification (TE) and fuel switching programs that will result in greater annual loads in future forecast years, again diverting from statewide planning assumptions.

The output of the IRP process will be more accurate and useful to the extent it more closely reflects actual expectations. The most effective way to balance the need for uniformity with LSE-specific strategy differences is to set the technical requirements upon which uniformity

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13 Staff Proposal at A-14.

14 *Id*. at A-6.

will be based at a more general level. The Commission could, for example, specify the requirement based on emission levels and portfolio characteristics, rather than technology and resource-specific requirements.

At a minimum, the Commission should permit divergence from statewide standards to the extent it does not materially interfere with combining like-for-like with other portfolios. This will require a more detailed explanation from Staff regarding the specific technical problems encountered in aggregating plans for the 2017-2018 cycle to highlight areas with more or less flexibility for deviation. Importantly, however, the Commission should permit LSEs to more accurately reflect the percentage of clean resources they plan for their portfolios and changes to their load resulting from TE load growth, demand-side efforts, or other LSE-specific programs. Any LSE deviating from the RSP in these ways, however, should be required to substantiate its more refined assumptions.

3. Allowing LSEs to Present Non-Conforming Preferred Portfolios Provides Valuable Information

The Staff Proposal would permit LSEs to file only Conforming Portfolios, eliminating the Alternative Portfolio option employed in the 2017-2018 IRP cycle. The Staff Proposal explains that Staff found that "non-conforming portfolios were not very useful for aggregation."[15] As an initial matter, CalCCA recommends that the Staff work with LSEs to develop a shared understanding of the factors that prevented useful comparisons. Regardless of their usefulness for aggregation, however, non-conforming portfolios provide valuable information regarding LSEs' actual procurement preferences, unconstrained by Commission directives and informed by LSE-specific information and assumptions.

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[15] *Id*. at A-13.

Non-conforming portfolios reflect the inputs and assumptions that each LSE believes to be most accurate, based on each LSE's more granular (and accurate) knowledge of its customers, programs, goals, and territory. LSEs may have better knowledge of local demographic and usage patterns, thus, more accurate regional load growth projections and load shapes. LSEs may also be more familiar with local geography and renewable generation shapes. Several CCAs are investing in professional, technical modeling expertise to better project local load projections for this section IRP cycle in an effort to match local needs to their portfolio planning. For these and other reasons, non-conforming portfolios provide a "bottom-up" picture of LSE's preferred procurement, which at a minimum provides useful information to compare against portfolios selected in accordance with the Commission's "top-down" RSP.

For these reasons, CalCCA recommends that rather than prohibiting non-conforming portfolios, the Commission should focus on ways to: 1) more efficiently aggregate non-conforming portfolios; and 2) otherwise utilize the inputs and assumptions from non-conforming portfolios to develop future RSPs that more accurately reflect the power supply and energy demand of each LSE. Utilizing such information in the Staff's development of RSP can also help Staff identify renewable integration needs and procurement actions in the future.

C. Question 3: Confidentiality

> *Comment on the proposed process to allow non-market participants access to the confidential version of filings by signing a standard non-disclosure agreement. If you do not agree with the proposal, propose an alternative method.*

Staff makes three proposals regarding confidentiality of the data and information supporting IRP filings:[16]

[16] *Id*. at A-14 – A-15.

- Maximize the amount of data supporting the IRP filings that is made available to the public;
- Require LSEs to file motion to file any confidential data under seal at the time the filings are made, detailing the reasons for keeping the materials confidentiality; and,
- Make a confidential version available to non-market participants on the required filing date.

While CalCCA does not object to the first two recommendations, the third recommendation presents unique problems for CCAs.

Although CCAs are subject to the California Public Records Act (PRA),[17] some of the data underlying their IRP filings would not be subject to disclosure pursuant to specific exceptions provided in the Act. An exception exists for information provided confidentially to the Commission. The PRA maintains an exemption from the waiver provision only for disclosures "[m]ade to a governmental agency *that agrees to treat the disclosed material as confidential*."[18] There is no exemption that would extend to disclosure of the confidential information to "non-market participants." As a result, unlike the result for other LSEs, release of the information to non-market participants by a CCA means making the information *publicly* available.

In the last planning cycle, most CCAs provided public versions of their submissions on their websites and sent the confidential versions to the Energy Division. CalCCA recommends adopting a similar approach for this cycle.

D. Question 4: Other

Comment on any other aspect of Section 2 of the Staff Proposal.

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17 CAL. GOV. CODE §§ 6250, *et seq*.

18 *Id*. at § 6254.5(e) (emphasis added).

1. Definition of "Certify" (a Community Choice Aggregator Plan) and "Approve" (an IOU, ESP or CCA Plan)

The Staff Proposal defines "certify" in the context of the Commission's obligation with respect to a CCA's IRP filing. It provides:

> Public Utilities Code 454.52(b)(3) requires the CPUC to certify the integrated resource plans of CCAs. "Certify" requires a formal act of the Commission to determine that the CCA's Plan complies with the requirements of the statute and the process established via Public Utilities Code 454.51(a). In addition, the Commission must review the CCA Plans to determine any potential impacts on public utility bundled customers under Public Utilities Code Sections 451 and 454, among others.[19]

While the definition is generally headed in the right direction, CalCCA requests modifications to ensure statutory consistency.

California Public Utilities Code section 454.52(b)(3) requires that each CCA formally "submit" its integrated resources plan to its governing board "for approval" as consistent with the requirements of section 454.51(a). It further requires that each CCA "provide" its IRP to the Commission for "certification." To adequately distinguish between the roles of "approval" and "certification," CalCCA proposes to modify the definition, "certify" to read as follows:

> "Certify" requires an act of the Commission confirming that the CCA's IRP is consistent with the procedural requirements adopted by the Commission according to Section 454.52 and provides the information required by the Commission to develop its statewide portfolio and perform its statewide planning function.

The Staff Proposal also defines "approve" in the context of "an IOU, ESP or CCA plan"[20] stating:

> [T]he CPUC's obligation to approve an LSE's integrated resource plan derives from Public Utilities Code Section 454.52(b)(2), in

`19 Staff Proposal at A-5.
20 *Id*.

> addition to the CPUC obligation to ensure just and reasonable rates under Public Utilities Code Section 451.

This definition is in error. The Commission has no authority or obligation to "approve" a CCA's integrated resource plan; section 454.52(b)(3) makes clear that approval of a CCA's plan remains with the local government authority. In addition, the description of the activities under this definition, including the reference to section 454.52(b)(2) reasonable rates, apply only to IOUs, not to CCAs or ESPs. Consequently, the parenthetical following the definition should be modified to read: "(an IOU Plan)," striking the references to CCAs and ESPs.

2. Reference System Portfolio Resource Mix

The Staff Proposal states that "[i]f the Commission identifies a specific resource, mix of resources, and/or resource attributes from the Reference System Portfolio as necessary for renewable integration, the LSE must include its share of that resource."[21] As noted in Section A, above, the Staff Proposal does not define what "as necessary for renewable integration" means. The implication seems to be that a CCA must submit a plan that duplicates the Commission's directed RSP resource mix on a proportional basis. This interpretation, however, would be contrary to the statute and would undermine the Legislature's clear and repeated statements that CCAs should maintain procurement autonomy.[22]

In addition, while section 454.51 *expressly* requires that "*electrical corporations*" submit portfolios that comply with the portfolio identified by the Commission, it *does not* extend that requirement to CCAs. Instead, CCAs are only expressly required to either pay nonbypassable charges for or self-provide their share of the renewable integration need identified in the Commission's portfolio. Indeed, section 454.51 does not suggest that a CCA would be required

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21 *Id*. at A-14.

22 *See* CAL. PUB. UTIL. CODE §§ 366.2(a)(5), 380(b)(5).

to duplicate a portfolio prescribed by the Commission; instead, it provides qualitative factors through which the Commission can assess whether a CCA has met its share of the renewable integration need.[23]

To avoid running afoul of the statute, the Commission should, as CalCCA requests in Section A.1, define "renewable integration" resources to represent a particular subset of resources in the portfolio. In addition, among the Staff Proposal's alternatives,[24] the Commission should focus on "*resource attributes*," rather than "a specific resource" or a "mix of resources." Focusing on how a portfolio serves the grid or climate goals, rather than on the technology or type of resources within the portfolio, better aligns with the goal of maintaining CCA procurement autonomy and encourages LSEs to pursue renewable integration strategies which meet both statewide and LSE goals.

III. QUESTIONS RELATED TO SECTION 3: TECHNICAL REQUIREMENTS

A. Question 5: Assigned Load Forecast

Comment on the proposal for assigning load forecasts to individual LSEs using the California Energy Commission's (CEC's) Integrated Energy Policy Report (IEPR).

The CEC's "mid Baseline mid AAEE" version of the 2019 demand forecast[25] is a reasonable starting point, but the Commission should be flexible in the way in which the forecasts are applied. First, the loads of LSEs with peak loads below 200 megawatt (MW) may not be captured in the IEPR process. Similarly, energy efficiency programs administered by LSEs that do not utilize PPP funds would also not be captured in the IEPR forecast. Second, as discussed in response to Question 2, above, the Commission should allow LSEs to modify their

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[23] *Id.* at § 454.51(d).
[24] Staff Proposal at A-14.
[25] *Id.*

load forecasts based on reasonable expectations arising from the LSEs' individual program goals. For example, LSEs aggressively pursuing TE and fuel switching likely will have load forecasts that diverge from the IEPR forecast in later years, as will peak shaving efficiency measures and demand response. LSEs thus should be able to modify their forecasts if they can provide a reasonable basis for the modification. This flexibility goes hand in glove with the Staff Proposal to allow LSEs to provide their own load shape in the Clean System Power calculator tool. Modified load profiles should be justified quantitatively with assumptions and methodologies consistent with what is technically and economically achievable, and should include documentation regarding the LSEs plan to implement its load modification strategy.

B. Question 6: Greenhouse Gas (GHG) Planning Price

Comment on the proposal to eliminate the GHG planning price as an option to demonstrate compliance with the 2030 planning target.

CalCCA offers no comment on this question.

C. Question 7: GHG Emissions Benchmark.

Comment on the proposal to apply the same methodology used in the previous IRP cycle to calculate the 2030 GHG emissions benchmarks for individual LSEs.

CalCCA supports this approach, subject to two conditions. First, the target and methodology must be consistent with the adopted methodology in D.18-02-018. Second, the expected January 2020 date for publication of the GHG emissions benchmark does not permit LSEs adequate time to effectively integrate them into their submissions. Because the GHG emissions benchmark is a primary metric in the review of LSEs' plans, portfolios are built to meet the benchmark. Failure to provide the value until January could cause an LSE to be required to reconstruct a portfolio in short order to make the April submission date.

CalCCA requests that the Commission publish provisional values in late November 2019, subject to a final adjustment of not more than 5 percent when the IEPR values are published. Alternatively, if the Commission is not able to provide the benchmarks until January 2020, then the Commission should delay the date for LSE IRP submission to August 1, 2020 at the earliest.

D. Question 8: Reporting on IRP Planning Standards

Comment on the proposal to introduce planning standards, or metrics, to be reported by LSEs. Do you see value in requiring LSEs to report on specific planning standards? Why or why not?

CalCCA does not oppose adopting certain planning standards and metrics in principle, particularly to the extent these standards stay within statutory bounds. CalCCA provides comments on certain standards and metrics, including whether LSEs should be required to report on them, in response to later questions below.

E. Question 9: Use of IRP Planning Standards

Should planning standards be informational in this IRP cycle? Should the Commission consider using the planning standards in a future citation program? Why or why not?

CalCCA agrees with Staff's Proposal to treat planning standards as informational in this IRP cycle.[26] Whether the standards should be used in a future citation program, however, requires further evaluation.

As an initial matter, the scope of the Commission's authority to create a citation and penalty program is not clear, and the Commission should begin with legal briefing on the scope of such authority. Assuming such authority, however, CalCCA offers two recommendations.

First, where there are clear existing compliance obligations, such as the Commission's Resource Adequacy (RA) and RPS) programs, the Commission should refrain from creating

[26] *Id*. at A-17.

additional citation programs within the IRP program. Adding layers of compliance obligation and potential citations on top of these existing programs would create unnecessary administrative redundancy and burden for LSEs. Renewable Portfolio Standard penalties should remain within the RPS program, and RA penalties should remain within the scope of the RA program. Moreover, some of the analysis and metrics that Staff have chosen to use in the proposal may not be consistent with existing compliance programs. For instance, the proposed reliability assessment is based on load share instead of share of peak demand, which potentially renders the analysis result unreliable and unsuitable for citation.

Second, in other circumstances, CalCCA urges the Commission to consider the goals and intended results of a citation program if the Commission intends to adopt penalties in the future. The state's true policy goals and metrics are established by statute, including its GHG emission target/benchmarks, RPS goals, SB 100 GHG requirements, and Resource Adequacy. The Commission should ensure that the citation program is entirely aligned with the relevant statutory authority and does not undermine LSEs' abilities to achieve those goals. Any such program must also balance the need for and stringency of any such standards with the clear Legislative mandates requiring CCA procurement autonomy.

The topic raised by this question is far more important and complex than can be addressed in comments on the Staff Proposal. For the purposes of this exercise, the Commission should simply make clear that the standards will be informational for this planning cycle pending further exploration of enforcement mechanisms in a future proceeding.

F. Question 10: Areas for Planning Standards

Do you agree with the areas identified for planning standards? Are there other relevant areas that should be considered for planning standard development?

In general, the areas for planning standards seem reasonable but should be considered provisional pending a more detailed review following completion of this planning cycle. In addition, CalCCA offers comments on the proposed metrics in the standard-specific discussions below.

G. Question 11: Other

Comment on any other aspect of Section 3 of the Staff Proposal.

CalCCA has no additional comment on Section 3 of the Staff Proposal.

IV. QUESTIONS RELATED TO SECTION 4: LSE PLAN COMPONENTS

A. Question 12: Portfolio GHG Results

Comment on the proposed planning standard for the GHG benchmark and make any recommendations for improvement.

Greenhouse gas emissions should be measured not only by the LSE's portfolio GHG mass emissions (MMT),[27] but should include a metric to measure GHG emissions intensity (kg/kWh). An intensity metric better accounts for beneficial electrification, which increases electric sector emissions while reducing total emissions. Because there is no statutory requirement for any LSE to achieve a certain level of mass GHG emissions or GHG intensity, however, the standard should not be employed in a citation program.

B. Question 13: Reported Contracted and Planned Resources

Comment on the proposed differences in filing requirements for resources expected to be online in the medium term (by 2026) compared to those expected in the long term (2027-2030).

The Staff Proposal would use the same "viability information" for resources already procured as requested in the July 12, 2019 Contract Information Data Request.[28] CalCCA has

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[27] *See id.* at A-22 – A-23.

[28] *Id*. at A-23.

two concerns with the data request. It is unclear how the information requested will be used to assess the "viability" of contracted but not operational and planned resources and how such assessments would be used in the IRP process. Any methodology used to assess the viability of such resources should be developed in a transparent manner with full party participation. Further, the methodology should be developed first, and the specific data points to be used to assess viability should be determined by that methodology, not the other way around.

C. Question 14: IRP and RPS Plan Alignment

> *Do you have recommendations, beyond those already filed in the RPS rulemaking, regarding how to align the plans filed in IRP and RPS? Are there any examples of data tables that could be used to align the quantitative components of the two plans?*

The IRP and RPS Plan templates currently require information about similar contract data, but there are different types of information and levels of detail (*e.g.*, monthly vs. annual volumes) required between them. CalCCA proposes that opportunities be explored to define the data fields needed to form a master database from which the IRP and RPS templates can be populated. This simplified approach should improve efficiency of the process and the quality of the data that Staff receives.

D. Question 15. Local Air Pollutants

> *Comment on the proposed planning standard for local air pollutants and recommend any areas for improvement.*

Criteria pollutant emissions should be measured not only by the LSE's total portfolio mass emissions, but should include a metric to measure emissions intensity (kg/kWh). An intensity metric better accounts for beneficial electrification, which increases electric sector emissions while reducing total emissions. Because there is no statutory requirement for any LSE to achieve a certain level of criteria pollutant emissions or intensity in its portfolio, however, the standard should not be employed in a citation program.

E. Question 16: Disadvantaged Communities

> *Comment on the planning standard for the focus on disadvantaged communities and recommend any areas for improvement.*

Staff proposes to measure commitment to Disadvantaged Communities (DAC) customers using the "reported number of customers served 2018, 2019 and projected for 2020."[29] CalCCA agrees that ensuring commitment to DAC customers is an important planning goal. Measuring success, however, by the population that happens to be located in an LSE's area of service will not provide any information about an LSE's commitment. Qualitative and quantitative information on programs and services targeting DACs would be a better indicator.

CalCCA recommends against adopting a planning standard for this planning component. Instead, LSEs that serve disadvantaged communities should provide information related to rates, programs, or resource procurement that aim to relieve environmental and economic burden on these communities. CalCCA also recommends against creating a citation program for this planning component, since the information LSEs provide will likely be qualitative, and there is no statewide standard that sets statutory goals for LSEs.

F. Question 17: Costs and Rates

> *Do you agree with the proposal to assess the cost and rate impact of planned resources based on the 2019 Inputs and Assumptions used on the modeling for the Reference System Portfolio? If not, what other mechanism would you suggest and why?*

The Staff Proposal contemplates as a planning standard the "estimated cost of proposed planned resources based on 2019 I&A."[30] The metric appears to be stated as total dollars per

[29] *Id*. at A-26.
[30] *Id*.

year and it appears to be assessed on an aggregated basis. While tracking this metric would provide interesting information, it would not be a metric appropriately addressed through an LSE-specific citation program. Moreover, the cost of a CCA's resources does not fall within this Commission's jurisdiction.

The Staff Proposal for the planned resources revenue requirement is similar to the planned resources cost standard, except that instead of measuring the investment cost of resources, it would measure the annual revenue requirement. Again, while tracking this metric would provide interesting information, it would not be a metric appropriately addressed through an LSE-specific citation program. Like costs, a CCA's revenue requirement does not fall within this Commission's jurisdiction.

G. Question 18: Hydroelectric Generation Risk

Comment on the proposal to address the requirements of Decision (D.) 19-04-040 related to in-state drought risk. Are there improvements to how LSEs can plan and support efforts to manage this system-level risk?

CalCCA supports the Staff Proposal's direction on this issue. Several CCAs are undergoing a joint planning process to further refine our assumptions about hydroelectric generation availability and risk, and the modeling results will inform each CCA's drought risk management strategy.

H. Question 19: Hydroelectric generation risk

Are there strong examples of risk management plans that LSES already provide publicly in relation to other topics or purposes, for which the approaches could be helpful here? Include citations, if possible.

See response to Question 18. CalCCA has no further response at this time.

I. Question 20: Resource Shuffling

Comment on the proposal to address the requirements of D.19-04-040 in relation to the potential for resource shuffling and recommend any areas for improvement.

CalCCA would like to see a more coordinated and transparent analysis effort between the California Air Resources Board (CARB) and the Commission to ensure that any findings related to resource shuffling accurately reflect CARB's resource shuffling regulations. The results should be developed based on system-wide data that CARB has been collecting since the implementation of the cap and trade program. While LSEs are able to include assumptions about imports in the planning document, it is inappropriate to make any determinations and/or claims regarding emissions outside of the CAISO balancing authority area (BAA) or actual resource shuffling without CARB's validation.

J. Question 21: Apportioning Reliability Targets

> *Do you agree with the proposal to use the IEPR to apportion the planning targets for the proposed reliability standards? Indicate pros and cons of any suggested alternative methods.*

The Staff Proposal contemplates measuring an individual LSE's contribution to system and local reliability based on "contracted and planned resources shortfall."[31] This metric relates to performance under the RA program, which has its own compliance requirements and penalty framework. Moreover, it appears that despite the use of peak demand measures to allocate RA requirements, Staff proposes to allocate the requirement for planning purposes based on an LSE's share of retail sales to provide greater transparency in the planning exercise.

CalCCA submits that the retail-sales based analysis the Staff Proposal contemplates would not be a meaningful gauge of whether any individual LSE is satisfying its share of RA requirements. Moreover, it would be arbitrary to use the output of this analysis for purposes of any citation program, since it is only a very rough estimate of an LSE's compliance. Finally,

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[31] *Id*. at A-23 – A-24.

CalCCA would object to any publication of these results, given the risk of misrepresenting—either over- or underestimating—an individual LSE's compliance.

K. Question 22: Reliability Assessment/ESPs

> *Do you agree with the proposal for how to account for electric service providers as a group under the reliability assessments? Propose any alternatives and provide rationale.*

CalCCA provides no comments on this issue at this time, although it reserves the right to address the issue at a later time as development of IRP submissions and discussion further inform its view.

L. Question 23: Reliability Assessment/Double Counting

> *Will LSEs be able to complete the "Example System Planning Capacity vs. Contracted and Planned Resources Table" without double counting resources? Explain.*

CalCCA asks the Staff to clarify the concern related to double counting. Given that the resources are "planned," it should be possible to ensure that all potential resources are only listed once in an LSE's filing.

M. Question 24: Reliability Assessment/ELCC

> *Do you agree with the effective load carrying capacity assessment approach proposed under the system capacity requirement planning standard? Propose any alternatives and provide rationale.*

CalCCA provides no comments on this issue at this time, although it reserves the right to address the issue at a later time as development of IRP submissions and discussion further inform its view.

N. Question 25: Reliability Assessment/LOLE

> *What threshold should Staff use to determine whether to conduct a loss-of-load expectation study on any specific year of an aggregated portfolio?*

CalCCA supports performing Loss of Load Expectation (LOLE) studies for interim years within the IRP process to ensure sufficient lead time to identify necessary reliability needs.

Given that an LOLE threshold of 10 percent per year (or one event in 10 years) is the general standard, CalCCA recommends applying a 25 percent dead band, setting a final threshold LOLE level of 12.5 percent per year.

O. Question 26: Reliability Assessment/Local Capacity Areas

Comment on the LSE planning standard related to sufficient capacity in local capacity areas. Will it provide useful information for aggregation purposes? Propose any improvements.

See response to Question 21.

P. Question 27: Reliability Assessment/Other Planning Standards

Do you suggest any other reliability planning standards for LSE reporting? Describe analytical methods, necessary data, and modifications/improvements to existing tools to support the calculation. What additional information would the proposed standard(s) provide when assessing reliability, both for assessing the contribution of individual LSEs to system reliability and in the assessment of aggregated portfolios?

CalCCA provides no comments on this issue at this time, although it reserves the right to address the issue at a later time as development of IRP submissions and discussion further inform its view.

Q. Question 28: Resource Mix

Comment on the proposed planning standard for resource mix. Is there value in the LSEs reporting this standard? Suggest any improvements.

The Staff Proposal contemplates a metric that determines whether an LSE's plan accounts for the "resource mix identified in the optimal portfolio."[32] As discussed above in Section II.D.1, while the Commission has the authority to make sure that CCAs provide their share of the necessary renewable integration resources, the Commission does not have the authority to mandate a detailed resource mix for CCAs or ESPs.

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[32] *Id*. at A-35.

In addition, conforming to RSP's resource mix is somewhat unrealistic and may impinge CCAs' abilities to meet procurement goals set by their local governing boards. Functionally, CCAs are located in areas with different load profiles, and have different procurement goals, some of which include DERs, which are highly dependent on local programs and resource availability. CCAs are committed to play an important role in maintaining grid reliability, and many CCAs are procuring resources that follow their demand, which may not adhere to the assumptions embedded in the RSP.

For these reasons, while this metric may provide interesting information, it is not a candidate for a citation program that would assess individual LSEs. The metric could be improved by using an evaluation of how portfolios meet certain attributes, rather than whether they contain certain resource mixes. For example, LSEs can describe their strategies for diversifying their portfolios to integrate their renewable procurement and ensure grid reliability, including information provided in their Request for Offers. Even an improved metric, however, should not be used in a citation program given the potential for misalignment with statutory boundaries.

R. Question 29: Resource Oversubscription

Comment on the proposed requirement for LSEs to identify transmission capacity it will rely on for each zone. Can this reporting requirement improve LSE planning activities? Suggest any improvements.

CalCCA provides no comments on this issue at this time, although it reserves the right to address the issue at a later time as development of IRP submissions and discussion further inform its view.

S. Question 30: Action Plans

The requirements for LSE reporting on action plans remain fairly unchanged from the 2017-2018 cycle. Suggest any modifications or clarifications to requirements under this section.

CalCCA provides no comments on this issue at this time, although it reserves the right to address the issue at a later time as development of IRP submissions and discussion further inform its view.

T. Question 31: Clean Net Short Calculator Tool

Comment on the proposed changes to the methodology and calculator tool. Are there other changes or modifications that should be considered?

CalCCA believes that modifications should be considered to ensure accuracy and efficiency and look forward to working with Staff to develop reasonable modifications.

U. Question 32: Clean Net Short Calculator Tool/SMUJU

Because the calculator tool is designed to reflect California Independent System Operator (CAISO) operations, it may not be appropriate for California LSEs that do not serve load within the CAISO. What alternative means of estimating GHG emissions should those LSES be required to use?

CalCCA provides no comments on this issue.

V. Question 33: Clean Net Short Calculator Tool/Load-Modifier Toggle

In order to include the load-modifier toggle described in section 4.e.i.4., Staff would need to obtain hourly data on load shapes for each year of the planning horizon, or at least for 2030. Where should this data be obtained? Are there other options for whether and how to incorporate such a feature?

CalCCA provides no comments on this issue at this time, although it reserves the right to address the issue at a later time as development of IRP submissions and discussion further inform its view.

W. Question 34: Other

Comment on any other aspect of Section 4 of the Staff proposal.

CalCCA provides no comments on this issue at this time, although it reserves the right to address the issue at a later time as development of IRP submissions and discussion further inform its view.

V. OTHER QUESTIONS

A. Question 35: Bundled Procurement Plans

> *What modifications to the IRP process, if any, should the Commission make to facilitate coordination with investor-owned utility bundled procurement plans, required by Public Utilities Code Section 454.5?*

CalCCA provides no comments on this issue.

B. Question 36: Other

> *Provide any other additional comments and suggestions not already covered in the questions above.*

CalCCA provides no comments on this issue at this time, although it reserves the right to address the issue at a later time as development of IRP submissions and discussion further inform its view.

VI. CONCLUSION

CalCCA appreciates this opportunity to provide input in the Commission's development of IRP filing requirements and requests consideration of the recommendations offered in these comments.

Respectfully submitted,

Evelyn Kahl
Counsel to the
California Community Choice Association

October 14, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Examine Electric Utility De-Energization of Power Lines in Dangerous Conditions	Rulemaking 18-12-005 (Filed December 13, 2018)

CALIFORNIA COMMUNITY CHOICE ASSOCIATION PROPOSAL IN RESPONSE TO ASSIGNED COMMISSIONER'S PHASE 2 SCOPING MEMO AND RULING

September 17, 2019

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Table of Contents

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CALIFORNIA COMMUNITY CHOICE ASSOCIATION PROPOSAL IN RESPONSE TO ASSIGNED COMMISSIONER'S PHASE 2 SCOPING MEMO AND RULING

I. INTRODUCTION

Pursuant to the *Assigned Commissioner's Phase 2 Scoping Memo and Ruling* (Phase 2 Scoping Memo), issued August 14, 2019 the California Community Choice Association ("CalCCA"), the trade association representing Community Choice Aggregators ("CCAs"), submits this proposal in response to questions posed by the Assigned Commissioner in the Phase 2 Scoping Memo.

II. BACKGROUND

On December 13, 2018, the California Public Utilities Commission ("Commission" or "CPUC") opened Rulemaking ("R.") 18-12-005 to examine its rules allowing electric investor-owned utilities ("IOUs") to de-energize power lines in case of dangerous conditions that threaten life or property in California. In Phase 1, the Commission examined and adopted Public Safety Power Shutoff ("PSPS")[1] guidelines, focusing primarily on notification, communication and outreach, in advance of the 2019 wildfire season. Phase 1 culminated in adoption of Decision ("D.") 19-05-042 on May 31, 2019 ("Phase 1 Decision"). The guidelines adopted in the Phase 1 Decision, along with the guidelines previously adopted in 2018 in Resolution 8 of the Electric Safety and Reliability Branch ("ESRB-8"), are the entirety of the guidelines that are currently in effect governing the electric IOUs' PSPS programs.[2] Per the Phase 2 Scoping Memo, the purpose of Phase 2 is for the Commission to examine issues that were outside the scope of Phase 1, and for the Commission to

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[1] In accordance with the Phase 2 Scoping Memo, discussion of "de-energization" will be referred to as Public Safety Power Shutoff (PSPS).
[2] See D.19-05-042, Appendix A "*De-Energization (Public Safety Power Shut-Off) Guidelines.*"

revisit issues from Phase 1 that require additional examination and development. As part of Phase 2, the Commission will direct the development of comprehensive PSPS guidelines building upon those adopted in Resolution ESRB-8, the Phase 1 Decision and guidelines adopted in Phase 2.

III. CALCCA PROPOSAL ON PHASE 2, TRACK 1 ISSUES

***Issue 1*: Definitions And Standard Nomenclature**

a) Should the Commission adopt an updated definition of Critical Facilities to include the transportation sector, Department of Defense Facilities or other sectors?

b) Are there any differences among the IOU's medical baseline tariffs and medical baseline designations that should be updated to promote consistency across utilities for the PSPS programs?

c) What voltage level should be used to designate "distribution" versus "transmission" for PSPS events?

d) What nomenclature should the Commission adopt to describe the various periods of a PSPS event (i.e. the period during which the IOU has formed its emergency operations center but has not yet de-energized power lines, the period during which power is shut off, the re-energization period and the post-event time period)?

e) Are there any other terms that must be defined to ensure effective communication between utilities, Public Safety Partners, Critical Facilities and Critical Infrastructure and utility customers, e.g. "extreme wildfire conditions"?

CalCCA Proposal In Response To Issue 1(a) – Critical Facilities And Infrastructure:

CalCCA strongly supports the expansion of the definition of Critical Facilities and Infrastructure ("CFI") to include the transportation sector and proposes that the Commission expand the definition CFI to include additional critical facilities and infrastructure in other sectors. CalCCA believes that it is essential that the Commission address the impact of PSPS events on Department of Defense ("DOD") facilities, but believes that DOD facilities should be considered separately from other CFI, as DOD facilities raise their own unique set of national security, jurisdictional, resiliency, and confidentiality issues.

1. The Definition Of CFI Should Be Expanded To Include The Transportation Sector

CalCCA strongly supports expanding the definition of CFI to include certain transportation infrastructure and facilities that require electric power. These facilities are needed to preserve public health and safety by ensuring that communities have the ability to evacuate if necessary, during a PSPS event and that first responders have adequate roadway and transportation access to perform their duties. In particular, the following transportation-sector facilities should be included in the definition of CFI:

- Road and rail tunnels or underground systems that require electric ventilation – an example of such a facility is the Tom Lantos Tunnels on Highway 1 which utilizes exhaust fans to allow safe operation;
- All electrically-powered railroad infrastructure required for safe operation, including railroad control towers, track switches, railroad crossing guards, communications;
- Airports and air traffic control facilities, including runway lighting, radar, and communications facilities;
- Bridges that rely on electricity to function (moving bridges or drawbridges); and
- Water transportation safety infrastructure, including lighthouses and navigational lighting and essential port and harbor safety infrastructure (including the facilities needed to operate pilot boats).

One of the challenges to notification will be ensuring that the proper authorities in charge of the various traffic control systems are notified (e.g. Highway 49 is under the jurisdiction of California Department of Transportation, not the local jurisdictions, and rail lines that have multiple parties owning different spurs). The IOUs should be directed to develop comprehensive contact lists for these systems in addition to other CFI.

2. <u>DOD Facilities Should Be Addressed Separately And Not Included In The Definition Of CFI</u>

CalCCA believes that it is essential that the Commission adopt comprehensive rules governing PSPS events as they relate to Department of Defense (DOD) facilities. However, DOD facilities should be treated as a separate class and should not be included in the definition of "critical facilities and infrastructure." Unlike other critical facilities and infrastructure, many DOD facilities already have built-in energy resiliency, and are served by their own infrastructure, security, and first responders, meaning that there would be little benefit in disclosing the location of DOD facilities potentially affected by PSPS events to Public Safety Partners. In addition, disclosing information regarding DOD facilities, including the location of DOD facilities, the circuits and substations that serve these facilities, load information regarding the facilities, could raise legitimate national security concerns. The Commission should not provide information about DOD facilities to parties in the same manner that it provides CFI information, and instead should work directly with the IOUs and DOD to develop separate PSPS protocols.

3. The Commission Should Adopt A Single Three-Tiered Definition Of CFI That Replaces Other Terms Like "Critical Facilities" And "Essential Service"

CalCCA proposes that the Commission adopt a single definition of "Critical Facilities and Infrastructure" to replace a number of terms currently being used in the PSPS context. This definition should be divided into three priority-based "tiers."

CalCCA notes its concern with the lack of consistency in the use of the terms like "critical facilities," "critical infrastructure," and "essential facilities" in the wildfire and de-energization context. For instance, while Appendix A of D.19-05-042 includes defines "Critical Facilities and Infrastructure," Appendix C of the same decision provides a slightly different definition for "Critical Facilities." Similarly, PG&E not only has a designation for a "critical facility," it also has a designation for "essential service." It is unclear whether this designation covers the same facilities as the definition of CFI. CalCCA recommends that the Commission, in this Decision, adopt a *single definition* of the term "Critical Facilities and Infrastructure" ("CFI") to be used in all de-energization and wildfire-related proceedings, and direct the use of this standard term rather than alternative terms and designations like "Critical Facilities" and "Essential Service." As defined, CalCCA further requests that information provided to Public Safety Partners include all CFI.

The definition of CFI should include all facilities identified in the CFI list. To qualify as CFI, a facility should meet all three of the following criteria:

- The facility/infrastructure provides an essential public service;
- The facility/infrastructure relies on electricity to provide this service; and
- The unmitigated disruption of the service provided by the facility/ infrastructure, even on a temporary basis, would threaten public health and safety or cause a significant disruption to the normal functioning of public life.

CalCCA further proposes that the Commission divide CFI into three priority-based "tiers." Tier 1 CFI would be defined as the facilities and infrastructure that present the most immediate health and safety needs, such as first responder, hospital, and water facilities. Tier 2 CFI would be defined as facilities that are essential to public health and safety, but present a less immediate need than Tier 1 CFI, such as K-12 schools and blood banks. Tier 3 CFI would be defined as facilities that are required for the normal functioning of public life but present the least immediate health and safety needs – facilities like colleges and homeless shelters. A complete list of CFI with CalCCA's proposed tier rankings is included as Attachment A to these comments.[3]

Dividing CFI into tiers will allow the Commission, the IOUs, and interested parties to better prioritize the PSPS notice provided to CFI operators, the targeting of resiliency resources, and the IOUs' required efforts to assess CFI backup generation needs and (where needed) provide backup generation resources.

4. <u>Additional Critical Facilities And Infrastructure Should Be Included In The Definition Of CFI.</u>

While the definition of CFI adopted in D.19-05-042 was a good start at providing an "interim" list of the critical facilities and infrastructure that could be impacted or compromised by a de-energization event, as the Commission itself recognized this list was not meant to be exhaustive or restrictive, and the Commission explicitly left the list open for further examination in Phase 2 of this proceeding.[4] CalCCA agrees with the facilities included in the D.19-05-042 list, but proposes that the list be expanded and clarified to include the following additional CFI. Specifically, CalCCA proposes that the CFI list be expanded as follows (with proposed deletions identified in strikethrough and proposed additions underlined):

- *Emergency Services Sector*: Police Stations; Fire Stations; Emergency Operations Centers; <u>emergency dispatch centers; designated disaster relief shelters/centers; municipal or county yards relied upon to support first responder vehicles and equipment, repair important infrastructure, and restore public services.</u>

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[3] Critical Facilities and Infrastructure (CFI) Priority Tier Categorization Chart (Appendix A). The Chart integrates D.19-05-042 Appendix A, Appendix C and adds CFI not included in either Appendix.
[4] At 74-75.

- *Government Facilities Sector*: ~~Schools~~; Jails and prisons; elementary schools; preschools; licensed daycare centers;[5] schools and facilities for disabled students; children's homes/shelters; middle schools; high schools; colleges and universities; homeless shelters.

- *Healthcare and Public Health Sector*: public health departments; medical facilities including hospitals, skilled nursing facilities, nursing homes, blood banks, health care facilities, dialysis centers and hospice facilities; residential/inpatient mental health facilities; assisted living facilities; cooling centers.

- *Energy Sector*: Public and private utility facilities vital to maintaining or restoring normal service, including, but not limited to, interconnected publicly owned utilities and electric cooperatives; facilities needed to ensure the safety of natural gas infrastructure; community choice aggregators

- *Water and Wastewater Systems Sector*: Facilities associated with the provision of drinking water or processing of wastewater including facilities used to pump, divert, transport, store, treat and deliver water or wastewater including, but not limited to: facilities needed to distribute water and maintain water pressure, including pump stations and water towers; water supply facilities, including transportation pipelines and canals, transportation pumps, and wells; facilities that ensure water potability, including treatment plants.

- *Communications Sector*: Communication carrier infrastructure including selective routers, central offices, head ends, cellular switches, remote terminals and cellular sites (or their functional equivalents); communications facilities relied upon by first responders, emergency service and CFI operators; communication infrastructure, including radio broadcast facilities, used for emergency broadcasts; cell phone network infrastructure not relied upon by emergency services; internet infrastructure not relied upon by emergency services.

[5] CalCCA notes that licensed daycare centers were included in the D.19-05-042 Appendix C definition of "Critical Facilities" but not the Decision's Appendix A list of CFI.

- *Chemical Sector:* Facilities associated with the provision of manufacturing, maintaining, or distributing hazardous materials and chemicals (including explosive, highly flammable, radioactive, and highly toxic materials), and oil refineries, chemical plants, decommissioned nuclear power plants and associated spent fuel storage facilities, and chemical/fuel pipelines.

Like the facilities and infrastructure identified in the D.19-05-042 interim CFI list, each of CalCCA's proposed additions provides an essential public service; relies on electricity to provide this service; and the unmitigated disruption of the service provided by the facility/infrastructure, even on a temporary basis, would threaten public health and safety or cause a significant disruption to the normal functioning of public life.

CalCCA Proposal In Response To Issue 1(b) – Medical Baseline:

CalCCA believes there may be variations in terminology, applications and rates for medical baseline. PG&E lists its Rule 19 which defines medical baseline and provides significant details on the program. PG&E also maintains a website that explains the program and contains enrollment instructions. SCE's medical baseline tariff is not currently available on its website, but it does have a website that explains the program and provides an application and Schedule MB-E contains very basic information. SDG&E, similar to SCE, maintains a website with basic information on the program and enrollment forms. While each of the IOUs' websites appear to do a sufficient job in informing potential enrollees in the program about their options and enrollment process, the diversity and disparity between the three IOUs regarding the information contained in their rules is problematic. CalCCA believes it is prudent for all of the IOUs to have a detailed Rule on medical baseline rules, regulations and processes similar to PG&E's Rule 19. The IOUs published rules are a key component for stakeholders to use as they navigate any issues with eligibility or enrollment.

In addition, CalCCA is aware that some IOUs use the designation of life support ("LS") for medical baseline customers whose equipment is of immediate critical need for life and health. These types of designations and their definitions should be transparent and uniform across each of the IOUs. Unfortunately, CalCCA has been unable to review this designation and how it is determined.

CalCCA proposes that in Phase 2 the Commission adopt a single, uniform definition for "LS" customers, as well as rules requiring that the IOUs take comprehensive steps to identify all LS customers and LS residents within their service territories, maintain and regularly update their LS lists, and make this information available to all Public Safety Partners, subject to compliance with the Commission's privacy rules. Each IOU should include with this designation what type of equipment a customer has to allow for appropriate prioritization and services to protect life and health In addition, PG&E allows customers to self-report as vulnerable for those who have a condition where their lives or health would be at risk should their electric or gas service be disconnected. These customers may not have a medical baseline designation. Based on the disparity of information easily accessible for parties to review, CalCCA proposes that the Commission conduct a review and comparison of IOU medical baseline tariffs to ensure consistency in programs and that all relevant and necessary information is provided to Public Safety Partners and first responders.

CalCCA Proposal In Response To Issue 1(c) – Transmission and Distribution:

The distinction between "distribution" and "transmission" facilities varies significantly, with different definitions adopted by the IOUs and interested agencies that differ in various contexts. For instance:

- PG&E's transmission interconnection guide defines its transmission voltages as 60 kV, 70 kV, 115 kV, and 230 kV[6]
- California Independent System Operator ("CAISO")-operated transmission lines are 70 kV or greater[7]
- North American Reliability Corporation ("NERC") reliability standards distinguish between high voltage transmission lines (200 kV and greater), transmission lines (100 kV – 200 kV) and distribution lines (below 100 kV)[8]

For the purposes of clarity and consistency in PSPS communication and notifications, CalCCA recommends that the Commission define voltage for transmission and distribution based on the CAISO cutoff, with transmission lines defined as lines of 70 kV or greater, and distribution lines defined as lines that operate at less than 70 kV.

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[6] At page 2, available at: https://www.pge.com/includes/docs/pdfs/shared/rates/tariffbook/ferc/tih/l3.pdf.
[7] Understanding Electricity, CAISO. Available at: http://www.caiso.com/about/Pages/OurBusiness/Understanding-electricity.aspx.
[8] Tree Trimming and Vegetation Management, available at: https://www.ferc.gov/industries/electric/indus-act/reliability/vegetation-mgt.asp.

CalCCA Proposal In Response To Issue 1(d) – PSPS Timeline:

CalCCA supports consistency in terms and asks that when the Commission considers terms used for pre-, during, post- PSPS, those terms be simple, understandable, and easy to translate into multiple languages. Using terms consistent with phased processes such as stage, implement, restore or prepare, respond, recover, could facilitate communication. The PSPS terms should also be differentiated enough from disaster response terminology to avoid confusion or conflict with other statutes and regulations. Counties and cities may have the strongest suggestions for proper terminology. Whatever terms are chosen, they should be applied consistently across the state.

CalCCA Proposal In Response To Issue 1(e) – Other Definitions:

CalCCA understands from its members and interaction with local governments that a variety of terminology needs to be defined and made consistent, in addition to the terms the Commission included in Appendices A and C of D.19-05-042. Further, in defining the nomenclature of pre and post terminology, IOUs should identify the various terms they assign to facilities and defining the difference between the terms. In addition to the terms discussed below, the Commission should consider adopting consistent statewide definitions for terms like "vulnerable population," "mobility impaired," "hard to reach," and "isolated community."

1. The Commission Should Adopt A Definition For "PSPS Risk" That Is Distinct From "Wildfire Risk Area"

Currently, in the de-energization context the Commission and IOUs use a customer's wildfire risk based on High Threat Fire District ("HTFD") designations and maps as a proxy for a customer's risk of experiencing a PSPS event. This is problematic, as wildfire risk only roughly correlates with PSPS risk due to the structure of the IOUs' distribution and transmission systems. As PG&E noted in its September 24, 2019 *Progress Report on Implementation of De-Energization Guidelines*, "Although a customer may not live or work in a HTFD, their power may be shut off if their community relies upon a line that passes through an area forecast to experience gusty winds and dry conditions combined with a heightened fire risk."[9] Thus, a customer located within a Tier 1 (low fire risk) area may still be at a very high risk of a PSPS event if they are served by a high-risk transmission line or distribution circuit, for instance a circuit that also serves customers in a high fire risk area.

[9] At 1.

To address the limited usefulness of HTFD maps in determining PSPS risk, CalCCA proposes that the Commission adopt the term "PSPS Risk," defined as a customer's risk of losing power due to a PSPS event (as opposed to a customer's or area's wildfire risk). CalCCA further Proposes that the Commission require that all distribution IOUs classify each of their *circuits* based on the projected risk that the circuit will experience PSPS over a given year and the projected duration (total) PSPS duration expected over the year (measured in total outage hours). The IOUs should be required to rank each of their circuits based on these projections, and higher risk circuits should be placed into the following "PSPS Risk Categories" defined as follows:

- High PSPS Risk – circuits in the top 10% (90th to 100th percentile) of the rankings (highest projected outage hours);
- Elevated PSPS Risk – circuits in the next 15% of the circuit rankings (75th to 90th percentile);
- Moderate PSPS Risk – circuits in the next 15% of the circuit risk rankings (60th to 75th percentile).

Each IOU should be required to provide all Public Safety Partners with complete maps and lists of all High, Elevated, and Moderate PSPS Risk circuits within its distribution service territory. The Commission should require that these lists be updated on an annual basis, based on operational information from the prior year. Each year, final updated lists and maps should be provided to the Commission and Public Safety Partners at least three months before the start of each fire season.

2. <u>The Commission Should Adopt A Three-Tiered Definition Of The Term "Increased Risk Individuals That Extends Beyond Medical Baseline Customers And Categorizes Vulnerable Residents According To Vulnerability To Harm During A PSPS Event.</u>

It is essential that the Commission recognize that an IOU's list of Medical Baseline customers is not a comprehensive list of all individuals at an increased risk of harm due to a PSPS event. In recognition of this fact, the Commission should adopt the term "Increased Risk Individuals" ("<u>IRI</u>") to refer to all individuals physically located within an IOU's distribution service territory who are at a significantly greater than average risk of harm due to a PSPS-event. Further, in order prioritize efforts to provide the most vulnerable individuals with notice, emergency response, evacuation services, and allocation of resources for emergency backup generation and energy storage, the Commission should adopt a three-tiered definition of IRIs:

- Tier 1 IRIs: individuals at a significant, immediate risk harm or death during PSPS events. This group should include individuals who rely on electrically powered medical equipment for immediate life-support needs.
- Tier 2 IRIs: individuals at a significant risk of serious harm or death during a PSPS event. This group should include vulnerable individuals such as:
  - Individuals who rely on electrically powered medical equipment for regular, but not immediate, life support of functions, including dialysis patients;
  - Individuals who rely on electrically powered wheelchairs for mobility;
  - Individuals who require regular doses of refrigerated medication to treat serious medical conditions;
  - Individuals at substantially increased risk of harm due to heat exposure due to age or medical conditions; and
  - Individuals undergoing chemotherapy or radiation therapy.
- Tier 3 IRIs: individuals at a substantially increased risk of harm during an extended PSPS event. This group should include vulnerable individuals such as:
  - Infants;
  - The elderly; and
  - Low income residents who may not have the resources to leave a PSPS affected area or prepare for a PSPS event.

More granular definitions that incorporate priority of need will improve the IOUs' and first responders' efforts to ensure safety when time is of the essence. Moving forward in this Rulemaking, the Commission should consider requiring that the IOUs develop and regularly update lists of IRIs and share these lists with Public Safety Partners during PSPS events.

***Issue 2*: Access and Functional Needs (AFN) Populations**

a) *What efforts can result in more complete contact lists of AFN utility customers while still maintaining legal and privacy protections?*

   i. *What policies or laws affect the sharing of information between the electric IOUs and state and local governments to facilitate the identification of AFN populations for* *public safety purposes? What, if any, changes should be considered, and which entity or entities has the authority to make such changes?*

b) *Are different methods of notification needed before, during, and after PSPS events depending on the needs of an individual AFN utility customer?*

CalCCA Proposal In Response To Issue 2(a) – Contact Lists:

CalCCA recommends that the Commission consider further modifying D.06-06-066 as it relates to confidentiality, the Public Utilities Code sections 454.5(g) and 583, and the information needed by first responders and Public Safety Partners as defined in the Phase 1 Decision. CalCCA also recommends the Commission direct IOUs to provide county and city emergency planners with contact information for Medical Baseline and other electricity-dependent vulnerable customers, as defined, for outreach and planning purposes outside of an identified potential PSPS event. This will allow safety officials to identify resources needed in advance to ensure the safety of this population if and when a PSPS event occurs. Providing the information to emergency planners and responders only when a PSPS event is imminent or occurring may result in resources, such as portable generators or transportation to medical facilities may not be available to those who need them, thereby putting their lives at risk. Advanced information will aid with advanced planning and preparations.

PSPS events do not fit the classic definition of an emergency, and thus do not activate the normal triggers for initiating an emergency response. While risks to those medically dependent on electricity can be high during a PSPS event, providing medical baseline information gives first responders only a subset of affected vulnerable customers. The CPUC also should recognize that PSPS events can be particularly hard upon low income families that may not have the financial resources to prepare for a multi-day power outage. These customers are also particularly at risk due to lost work and compensation, lost access to social services during a PSPS event, and limited public transportation. The Commission should consider expanding the information provided to first responders and public safety partners to include designations of CARE and FERA customers, especially in advance of PSPS events for the purposes of local planning.

Local governments can use CARE/FERA information to identify areas within their communities that may need additional support during a PSPS event and to prioritize areas for IOUs in terms of resilient center placements. CARE/FERA may account for 10% to 30% of customers in a given area, and these customers include low income seniors, families with young children, and individuals on public assistance or fixed incomes. The potential negative impacts to these vulnerable populations could be significant. These factors should be considered along with the PSPS Risk criteria for IOU risk assessments and placement of resilient centers with input from local governments. In addition, during declared emergencies the federal government will reimburse local governments if proper documentation is provided. The Commission should consider a process for reimbursement of local governments for response efforts related to PSPS events. In addition, the IOUs should be required to identify, maintain, and regularly update lists of IRIs in their service territories.

CalCCA Proposal In Response To Issue 2(a)(i) – Information Sharing Laws/Policies:

Based on the CCAs' conversations with emergency professionals in their local jurisdictions, CalCCA proposes that as part of this reconsideration, the Commission should invite at minimum representatives from the following organizations to provide comments and direction on identifying critical information for AFN:

(a) County Health and Human Services Directors;

(b) Medical Health Operational Area Coordinator ("MHOAC") for each jurisdiction;

(c) Regional Disaster and Medical Health Coordinator ("RDMHC") and regional disaster and medical health specialist ("RDMHS");

(d) California Office of Emergency Services ("CalOES") Office of Access and Functional Needs representatives; and

(e) California Department of Social Services Disaster Services Bureau representatives.

CalCCA Proposal In Response To Issue 2(b) – AFN Notification:

CalCCA requests the Commission consider the issue of Master meters and submeters as it relates to the ability of constituents to receive notifications. Customers with submeters (i.e., certain apartment complexes and mobile home parks) could not sign up for alerts initially because alerts currently require an account number, which submeters do not have. One of the IOUs implemented the idea of allowing any individual to register for notifications based upon their zip code. This raised the question: *what problems does this cause since zip codes are so broad, cross communities, counties and geography*? For example, in a PG&E June 2019 PSPS event, reliance upon the 5-digit zip code identifier resulted alerts to local agencies stating impacted communities included individuals in Auburn, Nevada County. The city of Auburn is in Placer County, and the targeted area, an unincorporated area of Nevada County known as Lake of the Pines, is more than 10 miles away. The 5-digit zip code identifier may be too broad alone. However, the US Postal Service has an additional 4-digit sub area identifier which could be employed that could prove valuable in better refining the areas affected by a PSPS event. Refining the area to a 9-digit zip code identifier could provide more precise and effective notifications. CalCCA recommends that the Commission direct the IOUs to investigate additional options for permitting submeter individuals to have access to PSPS information that is more refined.

CalCCA also recommends the Commission consider revisiting its rulings on confidential customer data for the purposes of allowing first responders and Public Safety Partners to access necessary data in advance of PSPS events to prepare response plans, evacuation and transportation plans, and resilient center location evaluations. Data on Medical Baseline and CARE/FERA customers can assist in realistic assessment and development of these plans, and it can help communities prioritize where IOUs might best establish cooling and resilient centers.

***Issue 3*: PSPS Strategy And Decision-Making**

a) *What criteria should the Commission evaluate when assessing whether PSPS is being used as a measure of last resort?*
b) *Would adopting standardized wildfire risk criteria (e.g. wind speeds, weather conditions, vegetation dryness conditions, etc.) across utilities promote the public safety, and if so, what criteria should be adopted?*

CalCCA Proposal In Response To Issue 3(a) – Measure of Last Resort:

CalCCA notes that the Commission must be very clear regarding its definition of "measure of last resort" and should establish objective criteria and tools for situational awareness that the IOUs must use to determine whether PSPS event must be initiated. PG&E in its September 4, 2019 De-Energization Progress report notes that its Officer in Charge considers the availability of alternatives to a PSPS event and the ability to mitigate the risk of a PSPS event through notifications, community assistance locations, sectionalization, and the staging of restoration crews in advance.[10] What is not included in this consideration is the number of customers impacted, the

[10] PG&E Progress Report on Implementation of De-Energization Guidelines, September 4, 2019, at 1.

economic impact of the PSPS event, and the public safety risk from high heat conditions, which have their own public safety impacts. The establishment of criteria should not relieve the IOU of responsibility and liability in making PSPS decisions. In addition, the IOUs should document very clearly in their PSPS after incident reports all the information, data, conditions and issues they considered prior to initiating the PSPS event.

As the Commission gathers and reviews the PSPS after incident reports, the Commission could further refine and enhance the criteria IOUs need to consider before calling for a PSPS event. While wildfire risk criteria should inform IOU de-energization decision-making, they should not serve as a substitute for good judgement. The IOUs ultimately should be responsible for determining whether to trigger a PSPS event and their judgements should be subject to after-incident review.

CalCCA Proposal In Response To Issue 3(b) – Standardized Wildfire Risk Criteria:

CalCCA recommends that the Commission adopt a standard *minimum* set of criteria to be used by the IOUs in determining whether to call a PSPS event, and direct the IOUs to work with wildfire response experts like CalFire to determine whether additional criteria should be considered and how all criteria should be weighted, rather than having the Commission establish a single set of commonly weighted criteria "across utilities." This recommendation stems from the diversity of climates and environments throughout California.[11] Wildfire risk will vary across regions, and the conditions that relate to increased risk should reflect the unique characteristics of the location. As climate change continues and other factors that need consideration arise (e.g. bark beetle infestations or drought impacts), the wildfire experts can help the IOUs develop baseline regional criteria that can be refined and enhanced with more line/circuit level to help identify when to employ the "measure of last resort."

CalCCA proposes that the Commission adopt the following minimum list of criteria that all IOUs must measure, track, and consider when determining whether to call a PSPS event. These criteria should be tracked and assessed separately for each line/circuit. CalCCA's proposed minimum criteria are as follows:

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[11] U.S. Geological Survey Biogregions of the Pacific U.S., available at: https://www.usgs.gov/centers/werc/science/bioregions-pacific-us?qt-science_center_objects=0#qt-science_center_objects.

- Weather data:
    - Wind speed
    - Humidity
    - Temperature
    - Last precipitation
- Surrounding vegetation (outside of right of way ("ROW")) data:
    - Vegetation type (forest, conifer forest, brush, grassland, desert, etc.)
    - Vegetation density (quantified)
    - Vegetation moisture level (measured by drone or satellite)
- ROW condition:
    - Width of ROW
    - Last brush clearing
    - Last line patrol by arborist or forester
    - Current vegetation density in ROW (quantified)
    - Current vegetation moisture in ROW
- Line condition:
    - Line voltage
    - Pole height
    - Line ground clearance (lowest points at temperature and loading levels)
    - Pole type (wood, steel, undergrounded, etc.)
    - Conductor type (insulated vs. uninsulated)
    - Last line/pole inspection
    - Last inspection of safety devices installed on circuit
    - Age of poles, conductor, and safety devices

The Commission should require that all IOUs have the ability to collect required information (for instance, the ability to use satellites or drones to collect infrared vegetation moisture data) and consolidate all other data into a single database no later than May 1, 2020, before the start of the next fire season.

In addition, the Commission should require that before calling a PSPS event, the IOU balance the potential safety benefits to be gained from de-energizing each individual line/circuit against the potential harms caused by de-energizing each line/circuit. In this proceeding, the Commission should solicit proposals for a standard methodology for accounting for and quantifying potential de-energization harms. If adopted, this standard methodology should be used by all IOUs. Until such a methodology is adopted, CalCCA proposes that all IOUs be required to assess the likelihood and extent of the potential harm caused by de-energization using, at a minimum, the following interim data points:

- Potential Economic Impact:
    - Estimated cost of lost frozen/refrigerated foods and medications, based on number of residential customers, grocery stores, pharmacies, and food industry facilities served by the line/circuit; and
    - Estimated economic harm caused by lost productivity and interrupted commercial activity – based on number and size of commercial, industrial, government, etc. facilities served by a given line/circuit; multiplied by number of days of de-energization, with a modifier accounting for weekday vs. weekend de-energizations.
- Potential Public Health / Safety Impact:
    - Heat danger – based on expected temperatures during de-energization, known and estimated number of individuals living in residences served by a line/circuit that are at increased risk harm from high heat conditions;
    - Water/sanitation danger – danger that de-energization will result in interrupted water service, contaminated drinking water, interruption of wastewater service, or public exposure to wastewater; and
    - Medical equipment danger – danger that de-energization will interrupt power supply to essential life-supporting medical equipment. Based on known/estimated number of life-support individuals residing in residences or medical facilities served by a line or circuit.
- Potential Impact On IRI, AFN, And Other Vulnerable Groups:
    - Number of IRIs served by the line/circuit;

- Number of Medical Baseline customers served by the line/circuit;
- Number of AFN customers served by the line/circuit;
- Number of CARE/FERA customers served by the line/circuit; and
- Whether the line/circuit serves a disadvantaged community ("DAC").

<u>Issue 4</u>: Notification And Communication

a) What information should be communicated during a PSPS event as well as when power lines are being re-energized, and when (at what intervals) should that information be communicated?

b) Where Community Choice Aggregator (CCA) territories exist, what role should CCAs play in communicating about PSPS events?

c) Are additional communication guidelines required in the event of a transmission-level PSPS beyond those adopted in Resolution ESRB-8 and D.19-05-042?

<u>CalCCA Proposal In Response To Issue 4(a) – PSPS Communications:</u>

1. <u>Proposed Required Communications With Public Safety Partners</u>

CalCCA members have had varied experiences with IOU information dissemination during PSPS events. Based on these experiences and discussions with other Public Safety Partners, CalCCA proposes that all IOUs be required to establish a secure PSPS web portal ("Portal") that provides Public Safety Partners with all information necessary to perform their public health and safety and public service functions prior to, during, and after a PSPS event. CalCCA appreciates PG&E's effort in establishing its PSPS Portal. While CalCCA believes that the information provided on PG&E's Portal should be expanded and other aspects of the Portal can be improved and streamlined, as a general matter PG&E's Portal provides an example of the kind of Portal-based information sharing that all IOUs should be required to implement.

However, it is not enough for the IOUs to implement PSPS Portals – those portals must be used to provide Public Safety Partners with the information that they require. At a minimum, this information must include:

- A list of all lines/circuits (including sub-circuits and transmission lines) that the IOU plans to de-energize or has de-energized, with the lines/circuits identified by name, number, and connecting substation(s);

- For each line/circuit, the projected (or actual) date and time of de-energization, and the projected date and time of re-energization. These projections should be updated on a real-time basis;
- For each line/circuit, maps and Geographic Information System ("GIS") files[12] clearly showing all addresses and parcels (with lot numbers) that are served by the circuit or all circuits that are served by the transmission line;
- For each line/circuit, a complete list of all addresses and parcels (with lot numbers) that are served by the line/circuit;
- For each line/circuit, a complete list of all CFI served by the line/circuit, including the CFI address, nature of the CFI (i.e. hospital, cell tower, nursing home, etc.), known backup generation resources installed at the CFI, and primary and secondary 24-hour emergency contacts for the CFI operators;
- For each line/circuit, maps and GIS files showing the physical location and spatial relationship to the line/circuit of all CFI served by the line/circuit; and
- Status of IOU efforts to notify all affected Public Safety Partners and CFI operators. This information should be updated in real time. All notification efforts should be time-stamped and include the nature of the contact effort (call, text message, email, etc.) whether the contact effort was automated or made by a human, and whether each PSP or CFI operator has confirmed receipt of notification.

In addition, the following information should be made available to public safety partners in a separate, password protected area each IOU's PSPS Portal, with access limited to entities that are subject to the Commission's existing customer information privacy rules or that have signed a binding agreement with the Commission to handle this information in accordance with the Commission's privacy rules:

- For each line/circuit, a list of medical baseline customers, including address and contact information;

[12] When referencing GIS files, CalCCA refers to shapefiles, KMZ files, and other appropriate formats that would allow CCAs to view the information. CalCCA recognizes that the information requested could be consolidated into a single map with layers that may be turned on and off to allow viewing of different data.

- For each line/circuit, a list of all life support medical baseline customers and other customers and individuals who have notified the IOU that they rely on life support equipment, including address and contact information;
- For each line/circuit, a list of all known AFN customers, including address and contact information;
- For each line/circuit, maps and GIS files showing the location all medical baseline, life support, and AFN customers; and
- Status of IOU efforts to notify all medical baseline, life support, and AFN customers/residents. This information should be updated in real time. All notification efforts should be time-stamped, and include the nature of the contact effort (call, text message, email, in-person visit, etc.) whether the contact effort was automated or made by a human, and whether each customer or resident has confirmed receipt of notification.

2. <u>Proposed Required Communications With CCAs</u>

The information listed above is the absolute minimum amount of information needed for Public Safety Partners to effectively respond to PSPS events. Without knowing the specific circuits to be de-energized, and the addresses and parcels served by those circuits, it is virtually impossible for Public Safety Partners to direct resources to the impacted areas. And without knowing which critical facilities and infrastructure are served by each circuit, it is far more difficult for Public Safety Partners to prepare for potential public safety hazards (for instance from chemical facilities), breakdowns in communication networks, public health problems (for instance, form non-operational sanitation facilities), and myriad other potential issues. All information provided through the Portals should be updated on a real-time basis as additional information becomes available to the IOUs.

CCAs also have special PSPS information requirements in their role as electric generation service providers. In order to efficiently adapt procurement to potential PSPS events, avoid unnecessary procurement on behalf of customers who will be de-energized, and ensure adequate generation is available when de-energized customers come back online, CCAs need the following information:

- Historical load information for each circuit to be deenergized, based upon the specific calendar days for the PSPS event;
- Estimated load for each circuit to be deenergized during the PSPS period; and
- Load forecast for medical baseline and critical facilities customers to help discern

backup generation needs during a PSPS event.

This information should be provided to the CCAs either through a separate section of the Portal, or through direct communications with identified CCA representatives.

The load information provided to CCAs needs to be granular and specific, both in terms of the specific circuits/lines involved and time-specific load information. The CCAs have requested that the IOUs provide more relevant load data associated with a PSPS event to affected CCAs. During the June 2019 PG&E PSPS event, the load data that PG&E initially provided to MCE prior to the June 7-9 event was a so-called "P75 load forecast" by month. This is not the appropriate dataset from which to develop a load forecast for a PSPS event. A P75 monthly forecast averages out seasonal variation, which will skew results downward—especially since temperature and loads are higher during conditions which are likely to trigger PSPS events. It would be helpful to have more relevant information, such as a load forecast from PG&E based on actual conditions (seasonally or weather-adjusted). Lack of accurate or relevant data increases costs and affects CCA procurement and scheduling.[13]

The CCAs in PG&E territory have requested the circuit latitude and longitude information. PG&E codes this information as PREM_LAT and PREM_LONG. This information is critical for CCAs to improve the awareness of which customers will be de-energized during a PSPS event. The CCAs have requested that this information be provided as part of the standard 4013 provided during normal operations. D.04-12-046 issued in Phase 1 of the CCA implementation proceeding directs the utilities to provide all relevant information to CCAs and prospective CCAs, consistent with Section 366.2(c)(9). In that order the Commission stated:

> "AB 117 is clear in its intent to require the utilities to provide CCAs all customer and usage data even before the CCA begins offering service." We have found that AB 117 does not permit the utilities to second guess a CCA's request for relevant information and we will not revisit the issue here. The utilities' tariffs, therefore, shall include a provision that permits CCAs to access all relevant customer information, consistent with D.04-12-046 and the tariffs filed in compliance with D.04-12-046.[14]

This specific geographic information identifying the location of PSPS affected customers should not only be included in the standard 4013, but in all PSPS communications between IOUs and CCAs regarding affected customers. D.05-12-041 also notes that:

[13] Joint CCA Protest filed in response to Advice Letter 5582-E at 9.
[14] D.04-12-046 at 65.

> Section 366.2(c)(9) requires the utilities to provide all relevant customer information to CCAs and prospective CCAs and the Commission has found that the statute does not permit the utilities to determine the types of customer information required by CCAs and prospective CCAs. Utility tariffs therefore may not limit access to such information.[15]

CCAs require this information for both functional and compliance reasons. Electric Rule 23 Section C5(d) notes that CCAs are responsible for notifying their scheduling coordinators of curtailment or other load reduction events ordered by the CPUC or CAISO. To meet this requirement, the CCAs must have the relevant information so it is incumbent upon the IOU to provide this information to the CCA.

CalCCA also asks that CCAs be provided a proactive heads up that IOUs are considering initiating a PSPS event. Since weather monitoring is a significant factor, and 10-day weather forecasts are readily available, CCAs should be notified at the beginning of this 10-day window. CCAs should also be notified of any changes to the IOUs' plans throughout this 10-day window. Once the IOU decides to initiate a PSPS event, the CCAs should be provided affected customer load data associated with accompany customer information (SAIDs). CalCCA has been led to understand that the IOU grid operations teams will have this information as they must let CAISO know this level of detail.

3. <u>The IOUs Should Be Required To Secure Confirmed Notice From Public Safety Partners, CFI Operators, And IRIs</u>

CalCCA understands that most of the IOU notice efforts thus far have occurred through automated text messages, emails, and phone calls. CalCCA believes that this level of notice, combined with public notification through local media, is appropriate for general customers. However, three key groups of customers require immediate priority notification of a potential PSPS event: 1) Public Safety Partners; 2) CFI Operators; and 3) life support customers and other highly vulnerable individuals. For these groups, the IOUs should be required to make continued efforts to provide notice until the IOU receives confirmation that notice has been received.

Public Safety Partners require as much prior notification as possible in order to prepare to fulfill their essential public safety functions in the face of a potential PSPS event. CFI operators require immediate notice in order to take steps to ensure that their facilities are able to continue to

[15] D.05-12-041 at 12.

provide essential public services or do not threaten public health and safety in the event of an extended de-energization event. For instance, hospitals need as much prior notice as possible to check that their backup generation is operational, call in additional staff as needed, and prepare for additional PSPS-related emergency patients. Nursing homes and hospice facilities need adequate prior notice in order to relocate or evacuate residents if needed. Facilities that work with hazardous, explosive, or toxic materials may need to shut down or take additional steps while electricity is still available to prevent accidents. IRIs, including individuals who are at a significant risk of life-threatening harm due to a PSPS outage, need immediate, priority notice in order to evacuate the area, move to hospital facilities, or ensure that backup generation is fully fueled/charged and operational.

For these essential groups, automated phone calls, text messages, and/or emails from the IOUs are not adequate notice. Automated calls, especially from unfamiliar phone numbers during off hours, may be missed or disregarded and can easily be buried in the recipient's voicemail. Mass emails are subject to a variety of technical limitations and can be delayed or rejected by spam filters and similar security measures. Mass text messages raise similar technical concerns, especially since business lines and landlines may not have text message functionality.

In order to ensure that these groups receive adequate notice, CalCCA proposes that all IOUs be required to take the following steps:

- Send automated phone calls, emails, and text messages to Public Safety Partners, CFI Operators, and highly vulnerable individuals. All calls, emails, and texts should have an automated mechanism that allows the recipient to confirm receipt of the notice. For instance, upon receiving an automated call an individual could be asked to dial a certain code to confirm receipt. For automated text messages and emails, the recipient could be asked to send a reply text or email with the word "confirmed."
- For all Public Safety Partners, CFI Operators, and highly vulnerable individuals, the IOUs should be required to keep records, updated in real time, of each attempt to provide notice until confirmation is received. The records should include the exact time of attempted notice, the method of notice (distinguishing between automated and human contact attempts), and the time confirmation of notice was received.
- If an IOU is not able to secure confirmation through automated notice, the IOU should be required to make all necessary attempts to provide timely notice through

non-automated means, including telephone calls and in-person visits from PG&E staff.

- For CFI Operators, IOU efforts to secure confirmation of notice through non-automated means should be prioritized based on the CFI's Tier, with priority notice efforts directed to Tier 1 CFI operators.

4. The Commission Should Address Privacy And Confidentiality Issues Related To PSPS Disclosures In A Careful Policy Review

CalCCA further proposes that the Commission adopt the general rule that all PSPS-related information should be provided to every Public Safety Partner without requiring the execution of a non-disclosure agreement or other limitations to access that may chill information sharing and lifesaving efforts unless there is a specific, reasonable, and overriding privacy, confidentiality, or other policy reason for limiting access. Of the information that CalCCA has identified as necessary for Public Safety Partners in general, only two categories legitimately raise such concerns: 1) identifying information for medical baseline or other vulnerable customers; and 2) locational and contact information for CFI facilities whose location and nature are not a matter of public record, and whose operators have articulated a specific reason (for instance security or market sensitivity) for keeping this information confidential.

These are complex issues that require a careful policy analysis that balances the needs of PSPs to personal or confidential information in order to conduct life-saving efforts and provide essential services with a variety of privacy and confidentiality considerations. CalCCA recommends that in this proceeding the Commission make it a priority to conduct a careful, deliberate consideration of these issues and adopt a single set of PSPS privacy and confidentiality rules that applies to all IOUs and PSPs (CalCCA notes that some PSPs may not be CPUC-jurisdictional, and may need to execute a standardized, CPUC-approved non-disclosure agreement ("NDA").

CalCCA further believes that the Commission should take immediate action to prohibit the IOUs from making Public Safety Partner access to PSPS Portals or other essential PSPS information contingent on the execution of an overbroad, IOU-developed NDA. This is a matter of immediate concern – PG&E has informed a number of CCAs, Cities, and Counties that access to a significant amount of essential PSPS information is going to be made contingent upon the execution of an NDA drafted by PG&E. CalCCA fundamentally opposes this approach. There is no legitimate policy basis for denying any Public Safety Partner access to all PSPS information other than the two categories identified above. Further, these two categories are already protected by Commission privacy rules, rendering an NDA unnecessary for state and local entities that are subject to the Commission's jurisdiction on these matters. For CCAs in particular NDAs are doubly unnecessary, as CCAs are fully subject to the Commission's privacy rules and already have NDAs with their distribution IOUs in place. CalCCA further notes that it has the right to access this information under Electric Rule NO. 23, Section C3(c) which states "A CCA has the option to request additional customer information pursuant to Schedule E-CCAINFO",[16] CCAs have the right to request additional information related to their customers.

In addition to being unnecessary, IOU-imposed NDAs that have not been reviewed by the Commission raise significant safety concerns. Overbroad NDAs may be used by IOUs to shield themselves from investigations, liability, and post-facto reasonableness reviews of their de-energization decisions and wildfire prevention efforts. NDAs may vary between IOU and IOU, and within an IOU, from one Public Safety Partner to another, potentially complicating and delaying the sharing information and creating a chilling effect on lifesaving efforts.

While CalCCA strongly supports the protection of customer privacy, CalCCA does not believe that confidentiality requirements should be unilaterally adopted and enforced by the IOUs through contracts that have been neither reviewed nor approved by the Commission. In order to address this problem, CalCCA asks that the Commission take the following steps:

- The Commission should instruct the IOUs to provide all Public Safety Partners with access to all Portal information *without having to sign a non-disclosure agreement* with the exception of the two categories of information identified above.
- The Commission should require that lists of medical baseline customers and non-public, confidential CFI facilities be made accessible to all Public Safety Partners are subject to the Commission's customer privacy rules.
- The Commission should instruct the IOUs that they may only require an NDA to access PSPS information for the two categories of information listed above, and an NDA may only be required of Public Safety Partners that are not subject to the Commission's privacy rules.

[16] Electric Rule No. 23, Section C 3 (c) at 12.

- The Commission should prohibit the IOUs from requiring or enforcing NDAs that go beyond the specific scope of protecting these two categories of information in the same manner as the Commission's existing privacy rules.
- The Commission should require that all NDAs be temporary, valid only until the Commission's adoption of PSPS Privacy and Confidentiality Rules in this proceeding.

5. PSPS Notice Should Be Provided To All Public Safety Partners In Both Affected And Neighboring Jurisdictions

CalCCA proposes that notification of PSPS events extend to the Public Safety Partners that neighbor areas slated for a PSPS event. This will help ensure neighboring communities that may wish to coordinate resources to respond to a PSPS event are on notice. CalCCA also underscores the need to notify all areas potentially affected by a PSPS event due to the configuration of the networked transmission system. PG&E noted in its introduction to its PSPS Program Report, that beginning in 2019, it expanded its PSPS program will include all electric lines (transmission and distribution) that pass through High Fire Threat Districts (HTFDs). PG&E further noted that: "Although a customer may not live or work in a HTFD, their power may be shut off if their community relies upon a line that passes through an area forecast to experience gusty winds and dry conditions combined with a heightened fire risk."[17] PG&E further states that:

> PG&E will then conduct power flow assessments and fault-duty (short circuit) studies in coordination with the California Independent System Operator (CAISO) to ensure that the initial transmission PSPS scope is feasible and will not compromise reliable bulk power system operations. This step is critical to support compliance with Federal Energy Regulatory Commission (FERC) and North American Electric Reliability Corporation (NERC) reliability standards and that de-energizations will not negatively impact bulk power system integrity. This assessment process will identify the total count of customers who are likely to be impacted by a transmission PSPS event, including any publicly owned utilities/electric cooperatives, adjacent jurisdictions, and small/multi-jurisdictional utilities, as well as other facilities interconnected at the transmission level. This step may also result in the identification of additional downstream PG&E distribution customers that would be impacted by transmission de-energization. Because of the configuration of the networked transmission system, customers and entities impacted by a transmission PSPS event may not be directly located within the weather event footprint itself or in a HTFD location, as designated by the CPUC. [18]

[17] PG&E Progress Report on Implementation of De-Energization Guidelines, September 4, 2019, at 1.
[18] Id. at 4-5.

Because the impacts from a PSPS event can have far-reaching impacts, beyond the scope of the area with conditions that would trigger an event, CalCCA recommends that PSPS notifications be expanded to include all impacted and neighboring areas. In addition, CalCCA recommends that the Commission should develop a list of criteria for prioritizing the allocation of resiliency resources and creation of cooling centers that includes but is not limited to likelihood of PSPS Risk, the designations of Tier-2 and Tier-3 HTFD, the number of customers impacted, the economic impacts, CFI impacts, and community and AFN needs. These criteria should be developed through workshops with stakeholders.

<u>CalCCA Proposal In Response To Issue 4(b) – Role of CCAs:</u>

The responsibility for notification lies strictly upon the IOUs under the existing PSPS guidelines. This approach is appropriate given the IOUs are the grid operators and the ultimate PSPS decisionmakers. CCAs lack the necessary information to adequately and accurately provide communications about PSPS events. CCAs necessarily must receive this information from an IOU. CCAs have received inconsistent information from IOUs associated with PSPS events and such information-sharing regularly diverges from agreed-upon protocols. Placing an expectation on CCAs to communicate about PSPS events creates a risk that incorrect and untimely information will be shared which presents serious health and safety risks.

This approach is supported by Electric Rule No. 23 C5(a) which states regarding, “Customer Inquiries Related To Emergency Situations And Outages” that “PG&E shall be responsible for responding to all inquiries related to distribution or transmission service, emergency system conditions, outages and safety situations. Customers contacting the CCA with such inquiries shall be referred directly to PG&E.” SCE has similar language in its Electric Rule 23, and SDG&E’s Electric Rule 27 also contains this language.

It is appropriate that the IOUs have the sole responsibility to provide notice of possible PSPS events and regular updates to customers, Public Safety Partners, and CFI operators, and that the IOUs bear all responsibility for mitigating the impacts of PSPS events through appropriate communications. The IOUs are responsible for building and maintaining their transmission and distribution systems, which serve all bundled and CCA customers. All CCA customers remain IOU transmission and distribution customers. The IOUs have the sole power to call a PSPS event and are the only parties with direct access to the system, operational, and other information used to determine the time, place, and duration of an event.

The CCAs are community-based public agencies that have an interest in protecting the well-being of their customers and communities. The Commission recognized this role in the D.19-05-042, classifying CCAs as "Public Safety Partners." The CCAs have requested the IOUs share the list of vulnerable customers and CFI within the respective CCA service areas prior to PSPS events. As local public agencies, CCAs may be able to support the development of PSPS mitigation and preparation efforts in advance of these events. CCAs may be able to reduce the burden of PSPS events by implementing programs that provide storage and/or generation resources to support resilience at CFI or vulnerable customer locations within their service areas. These opportunities should be given appropriate weight and focus as part of ongoing and future Commission proceedings. As such, CCAs should be provided an opportunity to administer programs to develop and operate microgrid facilities supported by new grants and funding opportunities. that could mitigate impacts of PSPS events but could also represent opportunities to reduce greenhouse gas emissions and address resource adequacy and energy supply issues. Any discussion of a microgrid or resilient center installation within a CCA's service area should include a representative from the respective CCA. Further, as microgrids and other PSPS mitigation tools have interconnection components, CalCCA recommends that the Commission consider, as part of the Phase 2 Track 2 of this proceeding, performing analysis of the interconnection processes with a focus upon streamlining to reduce delays.

CalCCA Proposal In Response To Issue 4(c) – Additional Communications Guidelines:

While the PSPS proceeding addresses many issues, the Commission does not consider in its Scoping Memo for Phase 2 Track 1 how to address increased localized emissions and carbon dioxide emissions from the use of generators at large facilities as a result of PSPS, and the crossover issue of California Air Resources Board air quality permit restrictions and penalties for this equipment. Further, CalCCA notes that the Commission needs to include direction to the IOUs for creating documentation of PSPS protocols and guidelines per Appendix B of the Phase 1 Decision. These issues should be explored in the context of transmission- and distribution-level PSPS events.

***Issue 5**: PSPS And Transmission Lines*

a) What coordination is required between the electric IOUs and public safety partners, the California Independent System Operator, the Federal Energy Regulatory Commission and others to ensure safe PSPS events, which require the shut-off of transmission lines?

i. In addition to those listed above, with whom must the electric IOUs coordinate to prepare for and notice transmission [level PSPS events, e.g. adjacent affected jurisdictions, publicly owned utilities, etc., and how should such coordination occur?

b) How should the Commission evaluate the impacts of transmission line PSPS versus distribution level PSPS, and what guidelines should be adopted to sufficiently prepare for and mitigate those impacts? For example, some facilities, such as airports and large industrial facilities, may be connected at the transmission level and may be impacted differently than in the case of distribution outrages.

CalCCA Proposal In Response To Issue 5(a) – Coordination for Transmission-Level PSPS:

CalCCA has addressed the communication and data needs that exist for CCAs during PSPS events. It is essential that the Commission put public safety first and ensure that all Public Safety Partners, including CCAs, be provided with full notice and all relevant information regardless of whether a PSPS event occurs at the distribution or the transmission level. CalCCA notes with significant concern that PG&E has indicated they may not provide CCAs with any information in advance of a transmission-level PSPS event claiming it may be "market sensitive information." In Opening Comments of Track 1 of this proceeding, PG&E argued:

> The PD identifies municipal utilities and Community Choice Aggregators (CCAs) as "public safety partners," with whom the IOUs are required to communicate about a potential PSPS in advance of informing the general public. PG&E understands and appreciates the need to coordinate with these two entities, however, this requirement could conflict with Federal Energy Regulatory Commission (FERC) regulations. These two types of entities are electric transmission market participants, with whom FERC's standards of conduct prohibit sharing nonpublic information about the operation of the transmission grid, including de-energization of transmission lines. PG&E asks the Commission to modify the PD to provide an exception to only require providing notice in advance of notifying the general public to the extent it would not violate any other laws, regulations, or standards.[19]

Most recently, in PG&E's September 4, 2019 PSPS De-energization Implementation Progress report, PG&E states that it has sought FERC's guidance regarding providing notice of transmission PSPS information to market participants, and may change its current practice of sharing

[19] PG&E Opening Comments at 7-8.

PSPS information with market participants based on FERC's input.[20] The Commission should categorically reject this argument. Tellingly, despite prompting from the California Municipal Utilities Association in its Reply Comments for the Proposed Decision of Track 1 of this proceeding,[21] the IOUs were entirely unable to provide any actual example of how a CCA program could use PSPS information to gain an inappropriate market advantage. To the contrary, the only apparent market-related use of PSPS information is to allow CCAs to protect their customers by reducing procurement (and associated costs) on behalf of load that will lose service in a PSPS event. Further, advanced notice that the utility is considering a PSPS event is not equivalent to outage information because the PSPS event may not actually be called. If FERC rules require that transmission PSPS information be made public simultaneously to all market participants, then the Commission should require such publication rather than allowing the IOUs to withhold advanced notice of possible transmission-level PSPS outages. Most importantly, it must be recognized that PSPS events are unplanned outage events that create risks to the health and safety of all impacted communities and individuals. The public safety interests therein should outweigh the specter of abuse of such information by market participants.

The Commission should direct the IOUs to collaborate and cooperate with CCAs when CCAs propose to develop local microgrids, islanding for local generation, power-routing alternatives, resilient center location, and other response or mitigation efforts related to PSPS activities. The upcoming implementation of SB 1339 (Stern) in Rulemaking ("R.") 19-09-009 represents a substantial opportunity to accelerate the ability of all stakeholders to increase community resiliency through deployment of microgrids. To facilitate coordination with CAISO, the IOUs should share the communication they provide to CAISO regarding load curtailment and all circuit, substation, and transmission line shutoffs associated with PSPS events with the respective CCAs.

<u>CalCCA Proposal In Response To Issue 5(a)(i) – Additional Coordination:</u>

CalCCA provides no comment at this time but reserves the right to address this issue going forward.

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[20] Pacific Gas and Electric Company Progress Report on Implementation of De-Energization Guidelines, September 4, 2019 Section 2.3.3. FERC Standards of Conduct page 5.
[21] California Municipal Utilities Association, Reply Comments page 2.

<u>CalCCA Proposal In Response To Issue 5(b) – Evaluation of Transmission PSPS Impacts:</u>

Outages for facilities connected at the transmission-level can be a significant safety concern. Where possible, the Commission should encourage innovative approaches to grid management in cases where the affected IOU has an intertie with another provider who could provide an alternate route for power. Alternative interties may exist for areas subject to PSPS events and the Commission should direct IOUs to investigate options for providing power through alternative routes by other grid operators proactively. As part of this identification, the IOUs and other infrastructure operators should identify where the capacity of the lines might need adjusting. The Commission should direct utilities requesting load capacity increase for transmission and distribution lines to evaluate the possible use of the lines for mitigation in PSPS events in areas where other mitigation factors might not serve as efficiently.

<u>Issue 6</u>: Lessons Learned

a) *Are there lessons learned from recent PSPS events (since adoption of D.19-05-042) that inform the topics under consideration in Track 1?*

<u>CalCCA Proposal In Response To Issue 6(a) – Lessons Learned</u>

During previous PSPS events, the CCAs learned that while CCA might not be directly impacted by a pending PSPS event, if its neighboring CCA is affected, crossover issues may arise (e.g. CCAs may look to provide mutual aid/support). The Commission should expand notification of pending PSPS events to all impacted and adjacent CCAs in an IOU service territory. CCAs should be provided notice of possible PSPS events at least 10 days in advance and as soon as PG&E reasonably believes that a PSPS event is likely to occur. CCAs should be provided immediate notice when PG&E activates its Emergency Operations Center ("EOC").

In comments on PG&E's after incident report for the June 2019 PSPS event, Marin Clean Energy, Peninsula Clean Energy, and Pioneer Community Energy noted information and detail deficiencies in the documentation. CalCCA supports the requests put forth from the these CCAs and further requests that the Commission consider opening discussion with first responders and public safety partners regarding the types of information the IOUs should include in the PSPS after incident reports including: (1) all information considered in determining to call a PSPS event; (2) notification to water and wastewater agencies and communication providers; (3) attempts to provide notice to critical facility/infrastructure operators and vulnerable customers; and (4) details on methods and who IOUs attempted to contact and whether those contacts were successful so that first responders, CCAs, and local agencies can assist in continuous improvement in notification protocols and information.

IV. ISSUES TO BE CONSIDERED IN PHASE 2, TRACK 2

CalCCA recognizes that the Scoping Memo for Phase 2 Track 2 of the proceeding is still in development. As preliminary comments, CalCCA offers the following suggestions for inclusion in the Scoping Memo. Further, CalCCA asks the Commission to provide opportunities for parties to comment on the Scoping Memo and Ruling for Phase 2 Track 2 as the questions offered below illustrate the need for deeper discussions, risks, sector impact identification and refinement of the aspects of the PSPS proceeding. Additional issues for Track 2 may arise in response to the Comments of other Parties and the Scoping Memo and Ruling once it is issued. CalCCA reserves the right to raise additional issues that should be within the scope of Track 2: CalCCA comments as follows:

1. Lessons Learned

   a. *Based upon recent PSPS events since adoption of D.19-05-042, what changes or updates to the guidelines adopted in that decision and Resolution ESRB-8 should the Commission consider?*

CalCCA provides no comment at this time.

2. Notification and Communication

   a. *What are the impacts on communication services during a PSPS event (when power is shut-off)?*

   PSPS events will impact our primary modes of communication (e.g. cell phone and internet networks) which present a serious concern for communication to the affected public and coordination and communication among first responders, Public Safety Partners, and CFI. This topic merits a deeper discussion and the Commission should conduct workshops with Telecomm electricity, and other service providers to explore opportunities to mitigate the impacts of a PSPS event.

   b. *What communication parameters should the Commission require of the electric IOUs with all affected populations during a PSPS event when there may be a loss of* *critical communication infrastructure?*

This issue is relevant to all Californians but is acutely relevant to vulnerable populations subject to increased risk and should be explored further in track 2.

c. *How should communications occur if there is a loss of critical communication infrastructure?*

Adequate tools and plans to reach vulnerable individuals should be developed to ensure the safety of those at-risk populations. The Commission should explore this in track 2.

d. *What guidelines should the Commission adopt for notification and communication if local jurisdictions choose not to form an emergency operations center (EOC) during a PSPS event?*

e. CalCCA provides no comment at this time and encourages the Commission to explore this issue in track 2. *Should the Commission require standardized messaging across electric IOUs to avoid confusion and increase understanding by customers and public safety partners, and if so, how should the Commission go about adopting that standardized messaging*?

The Commission should consider using workshops to open the discussion about messaging, seeking stakeholder direction with a look toward developing consensus where possible. Coordination between IOUs and all partners should result in more efficient communication and avoid confusion and duplication.

f. *How should non-residents, such as tourists, who are in an area that will be affected by a PSPS event be notified and what is the role of the utility versus other public safety partners in identifying these populations and providing notice?*

The Commission needs to consult with the California Department of Tourism, and the regional and local Tourism bureaus and CalTrans which controls the electronic highway alert signs and safety broadcast messages. Because PSPS events have such a far-reaching impact, the Commission should look beyond traditional partners.

g. *Are additional notification and communication processes needed for PSPS events that affect customers outside of California's borders (e.g. Oregon, Nevada, Arizona,* *Mexico) or that may impact Federal (e.g. Yosemite National Park) or tribal lands?*

The Commission should direct the IOUs to notify Vessel Traffic System and Vessel Traffic Information Systems at the Ports of PSPS events which will have direct bearing on all cargo and passenger vessel traffic. Further, the US Coast Guard could provide alerts to ships, particularly cruise ships planning Port visits to the PSPS event area allowing the ships to make alternative arrangements.

The Commission should further investigate the impacts of PSPS events on interstate commerce as it relates to the shipment and storage of goods and materials including but not limited to perishable goods, train cargo, and the pipeline infrastructure for petroleum products, where PSPS not only affects commerce but could also impact safety. In SCE's territory, special risk assessment should be conducted for the various oil platforms off the California coast. The Commission should request input from the State Lands Commission regarding the offshore and onshore facility risks.

h. *What strategies can be deployed to facilitate notice of PSPS events to speakers of non-English languages beyond those required in D.19-05-042?*

CalCCA encourages all outreach and notifications to customers to be designed to be understood by all customers. The IOUs should explore multiple channels of information including Community Based Organizations ("CBOs"). The Commission should explore this issue further in track 2.

i. *Are there any other guidelines the Commission should adopt in order to ensure effective notification and communication before, during and after a PSPS event?*

CalCCA provides no comment at this time.

3. <u>Mitigation</u>

a. *What services are needed during a PSPS event to mitigate risks to public safety, e.g. cooling centers, battery charging stations, access to drinking and bathing water?*

All of these services will mitigate risks to public safety. This issue should be explored through workshops and in coordination with local communities, since needs may differ among communities.

i. *Do the services needed during a PSPS event differ from the services needed during other types of electrical outages?*

Yes, primarily because the scale and duration of PSPS events may exceed other types of electrical outages. Additionally, the warm windy and fire-prone weather conditions that may trigger a PSPS event will be different than during other outages, some of which occur curing colder stormy conditions.

b. *Resolution ESRB-8 required that the IOUs help critical facilities evaluate preparedness for PSPS events, up to and including the provision of back- up generation. Who should bear the cost of back- up generation and should the Commission support the use of a specific back-up generation resource to mitigate environmental effects? Are existing Commission programs sufficient for these purposes?*

CalCCA provides no comment at this time.

c. *What mitigation measures should be considered for PSPS events that result in loss of power for more extended periods of time?*

CCAs are well positioned to collaborate with the IOUs and third party distributed energy resource ("DER") providers to develop microgrids and other resilience solutions in ways that align the entities' respective roles. In a general sense, those roles include IOUs as the deployer of poles and wires, CCAs as the primary electricity provider in their service areas, and DER providers as equipment providers. CCAs also have strong connections to other local government units and their local communities to be able to identify and develop community-specific solutions. In addition, because many CCAs have specific GHG reduction goals, CCAs have an interest in providing lower GHG options than traditional diesel generators for resilience services. These efforts will interact with the development of microgrid tariff (R.19-09-009), distribution resources planning (R.15-08-013), and integrated distribution energy resources proceedings (R.15-10-003) to determine how to develop these services among other Commission proceedings.

d. *Should the electric IOUs be required to consider claims for losses as a result of PSPS?*

Yes, but it should depend on the situation and the loss that resulted. Since these are discretionary actions, the IOUs may need to bear the financial responsibility to cover such claims. Imposing this liability on IOUs may help ensure that PSPS events are truly a "measure of last resort." However, the exact parameters for this liability should be developed in further workshops and comments.

e. What is the relationship between homeowner insurance/renter's insurance policies and losses as a result of PSPS events?

CalCCA provides no comment at this time.

4. <u>Should electric customers be billed for electric service during a PSPS event</u>*?*

Generally, the customers who have lost power during a PSPS event should not be billed for the variable costs, if any costs, of electric service. The relationship between PSPS shutoffs by IOUs and charges for energy services by LSEs and for delivery services by IOUs involves complexities that should be considered with stakeholder input. The cost impacts and potential cost-shifting should be considerations to be explored.

5. <u>PSPS Strategy</u>

a. How can the Commission ensure that the utilities are taking proactive measures to reduce the need for PSPS in the future (e.g. grid hardening, vegetation management, resiliency zones, etc.)? Should this issue be addressed in this proceeding or within the context of R.18-10-003?

This is a critical issue, especially since it involves a balancing of costs of PSPS events or wildfires against the costs of proactive measures. This is a policy question that should be further explored in track 2. The state should develop new tools to quantify these impacts and support decision making.

b. Should PSPS be weighed as a strategy differently if an area lacks distribution or transmission redundancy or if an area is located at the end of a transmission line?

Generally speaking, redundant transmission resources will mitigate the impacts of PSPS events. However, redundancy for an area alone may not be useful if the area itself must be deenergized. CalCCA believes that this will be a community-specific and an event-specific analysis, with which local CCAs will be well positioned to assist.

6. Re-Energization of Power Lines

a. Consistent with the sharing of criteria required in D.19-05-042, should the IOUs be required to share the criteria used to determine when to re-energize power lines with Public Safety Partners?

Yes. Publicly available guidelines should allow the public to develop a sense of the potential schedule for re-energization.

If so, what information should be shared, at what level of detail and according to what timeline?

The Commission should explore this issue through stakeholder feedback in track 2.

b. Any other issues not covered under notification/communication that are necessary to ensure the safe re-energization of power lines after a PSPS event.

CalCCA provides no comment at this time.

7. Requests to Delay PSPS Events?

a. Should the electric IOUs delay PSPS events, if requested?

The Commission should explore this issue through stakeholder feedback in track 2.

If so, what entities should be permitted to request delays?

The Commission should explore this issue through stakeholder feedback in track 2.

What criteria should the electric IOUs use to consider a request to delay?

The Commission should explore this issue through stakeholder feedback in track 2.

8. Education and Outreach

a. The electric IOUs are currently engaging in a comprehensive PSPS and wildfire safety/preparedness campaign. How should the Commission evaluate the effectiveness of that campaign?

CalCCA provides no comment at this time.

b. Is additional education and outreach needed beyond that currently being undertaken by the *electric IOUs and other state partners to educate the public on PSPS events, including what is entailed during a PSPS event, what tools are available to the public during these events, what to do in an emergency and how to receive information alerts during a power shutoff, and who the public should expect to hear from and when?*

Education and outreach for the public on PSPS events should continue and should be evaluated for effectiveness. The Commission should explore this issue through stakeholder feedback in track 2.

9. Evaluation of PSPS Events

a. *Should the Commission evaluate each PSPS event for reasonableness beyond the process adopted in Resolution ESRB-8 and D.19-05-042, and if so, what process should the Commission use to do so?*

The Commission should explore this issue through stakeholder feedback in track 2.

b. *What criteria should the Commission adopt to evaluate reasonableness of PSPS events?*

The Commission should explore this issue through stakeholder feedback in track 2.

V. CONCLUSION

CalCCA appreciates the opportunity to provide this proposal and comments to the Commission.

Respectfully Submitted,

/s/ Irene Moosen

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APPENDIX A: Critical Facilities and Infrastructure (CFI) Priority Tier Categorization

KEY:

Blue Text – Already Included in D.19-05-042 Appendix A
Green Text – Included in D.19-05-042 Appendix C but not D.19-05-042 Appendix A
Red Text – Not Included in Either D.19-05-042 Appendix A or C

Sector	Tier 1 Very High Priority – immediately needed during PSPS event to protect public health and safety.	Tier 2 High Priority – Important to public welfare but not immediately needed	Tier 3
Emergency Services Sector	• Police Stations • Fire Stations • Emergency Operations Centers • Emergency Dispatch Centers • Designated disaster relief shelters / centers.	• Municipal or county yards relied upon to support first responder vehicles / equipment, repair important infrastructure, and restore public services.	
Government Facilities Sector	• Jails and Prisons	• K-12 schools, pre-schools. • Licensed daycare centers. • Schools that specialize in educational services for the disabled. • Children's homes (foster care) • Homeless shelters	• Colleges and Universities
Healthcare and Public Health Sector	• Hospitals • Hospice • Skilled nursing facilities • Nursing homes • Public health departments • Healthcare Facilities • Residential / inpatient mental health facilities	• Blood banks • Dialysis Facilities	

	• Assisted Living Facilities • Cooling centers		
Energy Sector	• Facilities needed to ensure safety of natural gas infrastructure.	Public and private utility facilities vital to maintaining or restoring normal service, including, but not limited to: • interconnected publicly owned utilities; • electric cooperatives	
Water and Wastewater Systems Sector	Facilities associated with the provision of drinking water or processing of wastewater including facilities used to pump, divert, transport, store, treat and deliver water or wastewater including, but not limited to: • Facilities needed to distribute water and maintain water pressure, including pump stations and water towers. • Water supply facilities, including transportation pipelines and canals, transportation pumps, and wells. • Facilities that ensure water potability, including treatment plants.		
Communications Sector	Communication carrier infrastructure including selective routers, central offices, head ends, cellular switches, remote terminals and cellular sites (or their functional equivalents);	• Cell phone network infrastructure to the extent that it is not relied upon by first responders or for emergency notifications.	• Internet infrastructure to the extent that it is not relied upon by first responders or for

	• Communications facilities relied upon by first responders, emergency services, and CFI operators. • Communication infrastructure, including radio broadcast facilities, used for emergency broadcasts.		emergency notifications.
Chemical Sector	Facilities associated with the provision of manufacturing, maintaining, or distributing hazardous materials and chemicals. [including explosive, highly flammable, radioactive, and highly toxic materials]. • Oil refineries • Chemical plants • Decommissioned nuclear power plants and associated spent fuel storage facilities. • Chemical/fuel pipelines.		
Transportation Sector	• Air Traffic Control (and related infrastructure, including radar, communications, runway/navigational lights) • Essential Railroad Safety Facilities / Infrastructure (control towers, communications, rail switches) • Road/Rail tunnels or underground systems that rely on electricity for ventilation.		• Airport terminals and related facilities.

	• Bridges that rely on electricity to function safely, especially moving bridges. • Essential port and harbor safety infrastructure, including navigational lights and pilot boat facilities.		

DOCKETED	
Docket Number:	16-OIR-05
Project Title:	Power Source Disclosure - AB 1110 Implementation Rulemaking
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Comment Received From: Irene Moosen
Submitted On: 10/28/2019
Docket Number: 16-OIR-05

CalCCA Comments on the Modifications of Regulations Governing the Power Source Disclosure Program (AB 1110)

Additional submitted attachment is included below.

CALCCA
ADVANCING LOCAL ENERGY CHOICE cal-cca.org

October 28, 2019

California Energy Commission
Docket Unit, MS-4
Re: Docket No. 16-OIR-05
1516 Ninth Street
Sacramento, CA 95814-5512

CalCCA Comments on the Modifications of Regulations Governing the Power Source Disclosure Program (AB 1110)

The California Community Choice Association (CalCCA) submits the comments below on the Modifications of Regulations (Modified Regulations) Governing the Power Source Disclosure Program (PSD), issued in September 2019. CalCCA appreciates the opportunity to provide comments on the modified regulations. CalCCA offers support for numerous aspects of the Modified Regulations, along with recommendations for further changes.

CalCCA supports the Modified Regulations' approach to:

- Permit attestation of electricity portfolios offered by the board of directors of public agencies.
- Treatment of emissions associated with Cost Allocation Mechanism (CAM) resources.

CalCCA recommends the additional modifications to the Modified Regulations:

- Emissions associated with Portfolio Content Category (PCC) 2 products should be based on contracted-for renewable energy resources, not substitute power.
- If emissions associated with PCC 2 products remains unchanged, then the emission calculation exclusion date should be extended to December 31, 2019 to allow market participants to adjust their resource procurement strategies.
- PCC 3 products are eligible renewable portfolio standard (RPS) products, and should be reflected in the Power Content Label (PCL) based on the fuel mix used to generate the underlying renewable energy quantities.
- Emissions associated with distribution and transmission losses should be excluded from the PCL to avoid customer confusion.
- The Commission should adopt October 1 as the date by which annual disclosures must be provided to customers, for consistency with current practice.
- The Commission should issue a reporting template for new CCAs to use pursuant to section 1394.1(g).
- The Commission should be mindful of regional accounting inaccuracies and market impacts that will result from the proposed emissions accounting methodology for PCC 2 and PCC 3 products.
- The Commission should modify the definition of "specified purchase" to include certain after-the-fact purchases of generation from in-state and dynamically scheduled large hydroelectric and nuclear resources in 2019 and 2020 pursuant to a California Public Utilities Commission

(CPUC)-approved mechanism for allocating such resources among investor-owned utility portfolios and portfolios of other retail suppliers whose customers pay for those resources through the Power Charge Indifference Adjustment (PCIA), if the CPUC approves a reallocation mechanism for such resources.

I. CalCCA Supports the Self-Attestation Option for Public Agencies

CalCCA supports the changes the Modified Regulations made to Section 1394.2(a)(2). The Modified Regulations properly provide that public agency retail suppliers, such as publicly owned utilities (POUs) and community choice aggregators (CCAs), may have their Boards of Directors submit an attestation for verification of PCL reporting.

CalCCA urges the Commission to retain these provisions in the final regulations. Because public agencies conduct their business activities in public meetings and disclose a broad range of documentation and data related to resource planning, programs, and procurement, customers served by these agencies have opportunities to submit public comments. Furthermore, public agencies are subject to the Public Records Act (PRA) requests, providing additional transparency to their business activities. Therefore, public agencies that provide retail electricity to customers should not be subject to the same audit and verification procedures that are applicable to investor owned utilities (IOUs) in Section 1394.2(a)(1).

II. CalCCA Supports the Provision Related to CAM Resources

CalCCA supports the Commission's treatment of CAM and CAM-like resources, where the IOUs report the portion of procurement that is attributable to the IOUs serving their own load. CalCCA appreciates Commission staff's recognition that attributing the emissions associated with CAM and CAM-like resources to non-IOU LSEs would likely incur significant administrative burden and could result in inaccurate emission attribution that could mislead non-IOU LSE customers. CalCCA supports the retention of this treatment of CAM and CAM-like resources in the final regulations.

III. The Treatment of PCC 2 and PCC 3 Resources Creates Inconsistency between California's Regulations, Undermines Renewable Growth in the Western United States, and Would Cause Regional Emissions Accounting Inaccuracies

CalCCA recommends that the Commission re-examine its proposed treatment of PCC 2 and PCC 3 resources. The proposed regulations would disrupt the renewable energy market, undermine meaningful renewable energy development in the Western states, create regional power source emissions inaccuracies, and significantly increase costs for ratepayers. The proposed regulations essentially punish entities that have aggressive renewable and carbon-free procurement goals mandated by their governing boards.

In characterizing the Modified Regulations as *reporting* requirements rather than *compliance* requirements, the Commission underestimates the accountability impact of the disclosure. For LSEs with aggressive carbon free procurement goals, the Modified Regulations are the de facto compliance measurement instrument. AB1110's restrictions on marketing require compliance with the Modified Regulations by any retailer supplier that characterizes their portfolio as coming from certain types of resources, or as having certain emissions levels. The Modified Regulations establish a compliance regime, one that will interfere with rather than facilitate achievement of California's GHG-reduction goals.

1. *Differences in Contracts and Supporting Documents between PCC 1 and PCC 2/PCC 3 Products Do Not Affect Physical Flow of Energy or Related Emissions*

The difference between PCC 1 and PCC 2/PCC 3 resources lies in contractual terms, not in physical flows. Today, there is renewable energy that is dynamically scheduled into California from other parts of the Western Electricity Coordinating Council (WECC), which is verified based on contracts signed between buyers in California and generators that are located outside of California. It is uncertain whether at the instant of electricity generation that the electrons produced by those resources are flowing directly into California. Importantly, though, the "flows" can be verifiable through the creation of renewable energy credits (RECs) when renewable energy has been generated within WECC.

Contractual differences between these products do not cause any changes to physical power flows; specifically, contractual distinctions do not result in renewable or non-renewable electricity being "actually delivered" to any particular location. In other words, the electricity generated by a PCC 1 resource within California, with a contractual obligation to a Northern California entity, is not guaranteed to flow to that LSE's territory, and could potentially be exported to LSEs or balancing authority areas (BAAs) outside of California. Instead, the electricity that flows into the LSE's territory could be generated in-state, out-of-state, by renewable resources or non-renewable resources.

Therefore, attributing emissions to PCC 2 and PCC 3 resources based on substitute power instead of the contracted renewable resources is not based in science, and undermines the development of renewable resources within WECC and results in over-stated emissions in the Western states.

2. *The Goal of AB 1110 is not Verifying Greenhouse Gas (GHG) Emission Reduction in California or Anywhere in WECC*

Questions regarding the validity and verifiability of PCC 2 resources in reducing emissions have been referenced throughout the rulemaking.[1] First, nowhere in AB 1110 is GHG emission reduction mentioned as a goal. Second, it is unclear whether PCC 1 resources are indeed reducing emissions and displacing fossil fuel within California, on an electron by electron basis. In fact, natural gas resources have been needed to ensure reliability when intermittent renewable resources are not generating within California.

[1] Initial Statement of Reasons at pages 17, 18, 20.

It is not productive to argue the merits of emission reductions of particular renewable resources. AB 1110 requires disclosure of emissions *intensity* "for each purchase of electricity by a retail supplier to serve its retail customers."[2] AB 1110 does not require disclosure of emission *reductions*. When an electricity retailer purchases renewable resources, the retailer is making an investment in a zero-emission resource on the grid, whether it is within California or outside of California. As explained above, given that it is impossible to determine whether an electron generated by a renewable energy resource contracted by a specific LSE ultimately ends up in the LSE's service territory, the only way to verify that renewable energy has indeed been generated is through RECs.

CalCCA strongly urges the Commission to reconsider the treatment of PCC 2 and PCC 3 resources in adopting the final regulations by creating reporting standards that achieve the clearly stated goal of AB 1110 by deferring to REC-based accounting when attributing emission attributes to renewable energy purchases.

3. *The Inconsistent Treatment of Renewable Resources Imposes Significant Costs on Ratepayers, Particularly Those Who Have Chosen to Be Served by LSEs with Strong Renewable Procurement Targets*

By attributing emissions to PCC 2 resources based on the substitute power, and by excluding PCC 3 resources from accounting reflected under the "Eligible Renewable" subheading, the Commission essentially takes away tools that LSEs can utilize to meet their renewable energy development goals. Further, LSEs with ambitious renewable and carbon free procurement targets will have to purchase PCC 1 products or PCC 2 products that can be firmed and shaped with carbon-free resources.

As the supply of carbon free resources tightens in the WECC, firming and shaping PCC 2 resources with carbon free resources has become more and more expensive. As the staff acknowledges in its Fiscal Economic Impact Assessment, CCAs could incur $5,202,847 for fiscal year 2020 and 2021.[3] CalCCA believes that this estimate is unrealistically low. In its most recent analysis, Marin Clean Energy (MCE) estimates that shifting its procurement strategies to more closely resemble PG&E's expected portfolio emissions intensity and complying with the GHG-free procurement goals set by its Board would result in incremental cost increases approximating $9 million dollars per year. As East Bay Community Energy recently reported during a July meeting of its Executive Committee, the proposed changes to the PCL could increase procurement costs by over $8 million annually at today's levels of renewables procurement. While EBCE is actively conducting solicitations for in-state resources and has already signed agreements for over 550 MW of new resources located in California, the majority of these new projects will not come online until December 2021 or later.[4] In the meantime, in order to comply with direction from its Board of Directors, new CCAs like EBCE will need to consider alternative procurement strategies that are more expensive, such as swapping

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[2] AB 1110 Legislative Counsel's Digest.

[3] Fiscal Economic Impact Analysis, page 12.

[4] See https://ebce.org/ebce-expands-its-renewable-energy-and-storage-portfolio-with-two-new-contracts-and-memorandum-of-understanding/.

short-term transactions for PCC 2 and 3 resources for PCC 1 resources, or signing agreements solely with out-of-state resources that have transmission rights. Notably, these additional costs are not reflected in the Commission's Economic Impact Assessment. Other CCAs of similar sizes are also seeing similar cost increases. Similarly, by eliminating PCC 3 resources as an eligible renewable energy product from the PCL, CCAs will have to procure more expensive PCC 1 or PCC 2 resources to compete with their incumbent IOUs on the basis of electricity portfolio emission intensity.

Based on the analysis, CalCCA recommends the Commission reconsider its treatment of PCC 2 and PCC 3 resources in the final regulations.

IV. Grandfathering of PCC 2 Resources Needs to Be Meaningful

CalCCA appreciates the Commission proposing a later "grandfathering" date for PCC 2 resources than it did in past iterations of staff proposals, acknowledging the need for some allowance during the transition between different regulatory paradigms. While CalCCA believes that PCC 2 resources should be attributed emissions based on the underlying renewable resources that produced the REC, as stated above, CalCCA thanks the Commission for making an effort to help reduce the burden that LSEs and ratepayers may incur during the transition.

However, retail sellers have already procured 2019 resources under the existing RPS and PCL reporting requirements and will be unable to adjust their 2019 procurement to conform to regulations adopted at the end of 2019. Therefore, customers who paid for and were promised electricity portfolios with specific characteristic may be angry, confused and disappointed, which could damage an LSE's relationship with its customers and damage the reputation of the LSE and Commission. The outcome could include reduced customer interest in procuring additional renewable energy in the future.

Furthermore, the precedent of regulatory uncertainty created by changing the rules applicable to a year that has largely passed- even without direct financial or regulatory consequences- is likely to discourage RPS procurement and programs; such retro-active application has material financial, reputational, and procurement impacts on LSEs. This precedent will increase the costs of RPS procurement due to increased regulatory risk, and have a chilling effect on scope and depth of innovative efforts to procure beyond the mandated minimum regulatory RPS procurement requirement.

CalCCA recommends that the Commission adopt December 31, 2019 as the grandfathering date for PCC 2 resources. To ensure that the grandfathering date has real relief impact on ratepayers and retail sellers, time is needed to allow sellers to adapt their planning and procurement to avoid confusing customers with changed metrics applied retroactively. Since the regulations will be heard and potentially adopted on November 13, 2019 at the earliest and implemented thereafter, CalCCA suggests December 31, 2019 as the earliest possible date for the grandfathering provision as the adoption of the regulations will send the real signal for change to the market.

V. Emissions Associated with Distribution and Transmission Loss Should Not Be Disclosed to Avoid Customer Confusion

The disclosure of emission intensity associated with purchased electricity to account for distribution and transmission loss was proposed in the first draft of staff proposal, and eliminated subsequently in the second staff proposal.[5] CalCCA supported such change in its comments filed in February 2018 comments, and agreed with Commission staff's rationale then that the inclusion of the distribution and transmission loss would have created accounting complexities and inconsistency with other state reporting requirements (such as RPS), as well as confusion for customers.[6] Therefore, CalCCA is surprised by the re-introduction of distribution and transmission loss in the latest regulations, where transmission and distribution losses must be described in Section 1394(b)(3)(B).

Based on the language, it is unclear whether LSEs will need to disclose emissions associated with distribution and transmission line losses, which CalCCA still opposes for the aforementioned reasons. If that is not the intention, CalCCA asks the Commission for clarification on the need to disclose such losses, and whether such losses should be considered in each retail seller's emission intensity calculation.

VI. Exemptions on Retroactive Transactions Should Be Granted in the Years of 2019 and 2020

The definition of "specified purchase" in the Modified Regulations includes the following new final sentence: "Specified purchases shall be documented through purchase agreements exected prior to generation of the purchased electricity."[7]

CalCCA proposes a further amendment to the Modified Regulations' definition of specified purchase. The amended language below creates an exception to the requirement of a contract prior to generation, with the specific limitations below:

- Only available to retail suppliers whose customers pay PCIA with large hydroelectric and nuclear in their PCIA vintage
- Requires active agreement between retail suppliers to offer and to take generation

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[5] Revised Assembly Bill 1110 Implementation Rulemaking at page 12.

[6] CalCCA Comments on Assembly Bill 1110 Implementation Draft Proposal for Power Source Disclosure, filed February 23, 2018 at page 2.

[7] According to the initial statement of reasons at page 9: "Without a purchase agreement in place prior to the purchase of electricity from the market, one purchaser could by happenstance receive e-tags from a resource with low GHG emissions while another purchaser might randomly receive e-tags from a resource with high GHG emissions. Retail supplies cannot claim specific resources, or attributes of those resources, unless they intentionally purchased those specific resources; therefore electricity purchased from the open market can only be claimed as unspecified power, regardless of whether an e-tag can be used to trace to a specific source."

- Requires that the CPUC approve an after-the-fact mechanism for the transactions of such generation in 2019 and 2020
- Limited to large hydroelectric and nuclear resources
- Limited to in-state and dynamically scheduled resources on the CAISO controlled grid

The specific proposed language, as an addition to the "specified purchase" definition, is in italics below:

Specified purchases shall be documented through purchase agreements executed prior to generation of the purchased electricity, *except that purchases of generation from in-state or dynamically scheduled large hydroelectric and nuclear resources in 2019 and 2020 may be documented after the generation of the electricity when a retail supplier whose customers are paying for such resources through the California Public Utilities Commission-approved Power Charge Indifference Adjustment elects to purchase such in-state large hydroelectric or nuclear resources following a CPUC-approval of a mechanism for allocating such resources.*

The reason for the proposal is that, at present, many customers no longer taking retail electric service from investor-owned utilities (IOUs) continue to pay for the costs of IOU-owned large hydroelectric and nuclear resources. They do this through a California Public Utilities Commission (CPUC)-approved ratemaking mechanism called the Power Charge Indifference Adjustment (PCIA). These unbundled customers pay for large hydroelectric and nuclear resources whether they want to or not, with no opportunity to claim the PCL reporting associated with them.

IOUs are considering offering generation from in-state or dynamically scheduled large hydroelectric and nuclear resources to LSEs serving customers paying for those resources through the PCIA via an allocation mechanism. Such LSEs can elect to take their strip of large hydroelectric, or nuclear, or both, consistent with definition of specified purchase.

IOUs will need CPUC approvals for an allocation mechanism. Given the lead time for CPUC action on an IOU request for authority to make such an offer, the contracts for volumes that unbundled customers will have paid for in 2019 and the early part of 2020 cannot be executed prior to delivery (only some of 2020 can contracted for on a forward-looking basis). Thus the proposed change here, which is limited to fixing the targeted problem of LSEs serving unbundled customers who (1) have already paid for the resources through PCIA and (2) want an after-the-fact slice of 2019-20 in-state or dynamically scheduled large hydroelectric and/or nuclear generation counted on their PCL.

Whether the exception is invoked will be contingent on IOU filings at the CPUC requesting authority for an after-the-fact allocation, and CPUC approval of such a mechanism.

The Commission should adopt the limited and targeted exemptions for in-state or dynamically scheduled resources transacted between IOUs and non-IOU LSEs through the approved regulatory mechanism. These transactions are consistent with the Commission's definition of specified purchase, except for the timing of the documentation. Granting the exemptions will not impact other transactions.

VII. Annual Disclosures Should be Provided to Customers on or before October 1

CalCCA appreciates the Commission's aim to clarify, in Section 1394.1(b)(2), the date by which the PCL must be provided to customers. As the Commission has acknowledged, prior language specifying a deadline as of "the end of the first complete billing cycle for the third quarter of the year" is difficult to interpret.[8] However, as other parties noted in comments during the October 7 public workshop,[9] retail suppliers have historically managed this uncertainty by adopting a common practice: most retail suppliers currently provide their PCL to customers on or before October 1 each year. The current practice of providing the power content label by October 1 is consistent with the statutory language and should be adopted as the deadline, instead of August 30.

An additional benefit of the October 1 deadline is that it provides adequate spacing between customers' receipt of the PCL and the other required mailings they receive throughout the year. For example, in July of each year, all customers currently receive a Joint Rate Comparison, as required by the Public Utilities Commission. Providing the PCL by mail in October rather than August would avoid inundating customers with information all at once.

VIII. Additional Templates are Needed to Accommodate New CCAs

Section 13941.1(g) implements a provision of Public Utilities Code that offers new CCAs formed after January 1, 2016 additional time to disclose GHG emissions intensities. This provision will apply to a number of CCAs. CalCCA requests that the Commission, in addition to the templates it recently provided, also issue templates to be used by the CCAs that will be exempted from disclosing GHG emission intensities in 2019, pursuant to the regulations.[10]

IX. Conclusion

CalCCA appreciates the Commission staff's hard work on the Modified Regulations and looks forward to collaborating with staff to ensure the final regulatory language achieves the goal of improving customers' understanding of GHG emissions associated with their electricity purchases.

Sincerely,

Irene Moosen
Director of Regulatory Affairs
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(415) 587-7343 | irene@cal-cca.org

[8] Public Utilities Code, section 398.4 (c)
[9] Transcript of 10-07-2019 Lead Commissioner Workshop at p. 64, lines 19-22.
[10] Staff issued a Proposed Power Content Label Template and Proposed Annual Report Template on October 2, 2019.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) for Authority to Establish Its Authorized Cost of Capital for Utility Operations for 2020 and to Partially Reset the Annual Cost of Capital Adjustment Mechanism.	Application 19-04-014 (Filed April 22, 2019)
And Related Matters.	Application 19-04-015 Application 19-04-017 Application 19-04-018

CORRECTED JOINT CCA
3-DAY ADVANCE NOTICE OF EX PARTE COMMUNICATION

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October 1, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) for Authority to Establish Its Authorized Cost of Capital for Utility Operations for 2020 and to Partially Reset the Annual Cost of Capital Adjustment Mechanism.	Application 19-04-014 (Filed April 22, 2019)
And Related Matters.	Application 19-04-015 Application 19-04-017 Application 19-04-018

JOINT CCA
3-DAY ADVANCE NOTICE OF EX PARTE COMMUNICATION

Pursuant to Public Utilities Code Section 1701.1(e)(3) and Rule 8.2 of the California Public Utilities Commission's Rules of Practice and Procedure, Marin Clean Energy ("MCE"), East Bay Community Energy ("EBCE"), and Sonoma Clean Power ("SCP"), collectively the Joint CCAs, hereby provide advance notice of their scheduled *ex parte* communication scheduled with Jonathan Koltz, Legal Advisor to Commissioner Guzman Aceves. The meeting will occur in-person, at approximately 2:30 PM Pacific Time at the offices of the California Public Utilities Commission, located at 505 Van Ness Avenue, San Francisco, California on October 2, 2019. The following individual will participate in the *ex parte* communication for the Joint CCAs: Neal Reardon, SCP Director of Regulatory Affairs.

Respectfully submitted,

/s/ Daniel Settlemyer

Daniel Settlemyer
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October 1, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) for Authority to Establish Its Authorized Cost of Capital for Utility Operations for 2020 and to Partially Reset the Annual Cost of Capital Adjustment Mechanism.	Application 19-04-014 (Filed April 22, 2019)
And Related Matters.	Application 19-04-015 Application 19-04-017 Application 19-04-018

JOINT CCA NOTICE OF EX PARTE COMMUNICATION

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October 2, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) for Authority to Establish Its Authorized Cost of Capital for Utility Operations for 2020 and to Partially Reset the Annual Cost of Capital Adjustment Mechanism.	Application 19-04-014 (Filed April 22, 2019)
And Related Matters.	Application 19-04-015 Application 19-04-017 Application 19-04-018

JOINT CCA
NOTICE OF EX PARTE COMMUNICATION

Pursuant to Public Utilities Code Section 1701.1(e)(3) and Rule 8.4 of the California Public Utilities Commission's Rules of Practice and Procedure, Marin Clean Energy ("MCE"), East Bay Community Energy ("EBCE"), and Sonoma Clean Power ("SCP"), collectively the Joint CCAs, hereby provide notice of their *ex parte* communication.

DATE and TIME: From 3:00pm to approximately 3:30pm on September 30, 2019

LOCATION: California Public Utilities Commission ("CPUC"), 505 Van Ness Avenue, San Francisco, CA 94102

COMMUNICATION MEDIUM: In-person

WHO INITIATED COMMUNICATION: Joint CCAs

PERSONS PRESENT ON BEHALF OF THE COMMISSION: James Ralph, Chief of Staff to President Batjer

PERSONS PRESENT ON BEHALF OF INTERESTED PERSON: Michael Callahan, MCE Senior Policy Counsel

WRITTEN MATERIALS PROVIDED DURING THE EX PARTE COMMUNICATION: None

SUMMARY OF COMMUNICATION: Mr. Callahan provided the following arguments. The investor owned utilities ("IOUs") cannot justify increased risk based on departing load or power purchase agreements associated with departing load. The claims that their industry is in transition and that they cannot predict their customer base are moot because the CPUC mitigated these risks through establishing cost responsibility and recovery from all departing customers for above market costs through the power charge indifference adjustment (“PCIA”). Since the customer is responsible for this obligation, and not the new load serving entity (“LSE”), the utility will be made whole for their outstanding PPAs. Additionally, CPUC Resolution E-4907 (2018) creates a minimum of one-year notice with meet and confer obligations between the CCA and IOU to determine resource adequacy requirements before a CCA can launch or expand service to include a new community. The IOU concerns that they are now the provider of last resort (“POLR”) but rules for POLR don't exist yet should also be dismissed. The risk of being the POLR and needing to serve customers returned from another LSE is covered under the CPUC's bond posting requirement pursuant to Cal. Pub. Util. Code 394.25(e) and implemented in the recent Decision 18-05-022. This posting includes amounts for procurement costs and administrative per-customer costs. The IOU concerns about existing-PPA debt equivalency are mitigated through departing load carrying the PCIA responsibility with them to other LSEs. The risk of future-PPA debt equivalency is also reduced as the bundled customer load decreases due to departing load. The additional wildfire costs and risks should be mitigated through the passage of Assembly Bill 1054 (2019) and the eventual restructuring plan resulting from PG&E’s bankruptcy proceedings.

Respectfully submitted,

/s/ Daniel Settlemyer

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October 2, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) for Authority to Establish Its Authorized Cost of Capital for Utility Operations for 2020 and to Partially Reset the Annual Cost of Capital Adjustment Mechanism.	Application 19-04-014 (Filed April 22, 2019)
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JOINT CCA
NOTICE OF EX PARTE COMMUNICATION

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October 3, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) for Authority to Establish Its Authorized Cost of Capital for Utility Operations for 2020 and to Partially Reset the Annual Cost of Capital Adjustment Mechanism.	Application 19-04-014 (Filed April 22, 2019)
And Related Matters.	Application 19-04-015 Application 19-04-017 Application 19-04-018

JOINT CCA
NOTICE OF EX PARTE COMMUNICATION

Pursuant to Public Utilities Code Section 1701.1(e)(3) and Rule 8.4 of the California Public Utilities Commission's Rules of Practice and Procedure, Marin Clean Energy ("MCE"), East Bay Community Energy ("EBCE"), and Sonoma Clean Power ("SCP"), collectively the Joint CCAs, hereby provide notice of their *ex parte* communication.

DATE and TIME: From 2:30pm to approximately 3:00pm on October 2, 2019

LOCATION: California Public Utilities Commission ("CPUC"), 505 Van Ness Avenue, San Francisco, CA 94102

COMMUNICATION MEDIUM: In-person

WHO INITIATED COMMUNICATION: Joint CCAs

PERSONS PRESENT ON BEHALF OF THE COMMISSION: Adenike Adeyeye, Chief of Staff to Commissioner Guzman Aceves; and Jonathan Koltz, Legal Advisor to Commissioner Guzman Aceves

PERSONS PRESENT ON BEHALF OF INTERESTED PERSON: Neal Reardon, SCP Director, Regulatory Affairs

WRITTEN MATERIALS PROVIDED DURING THE EX PARTE COMMUNICATION: None

SUMMARY OF COMMUNICATION: Mr. Reardon provided the following arguments. The investor owned utilities ("IOUs") cannot justify increased risk based on departing load or power purchase agreements associated with departing load. The claims that their industry is in transition and that they cannot predict their customer base are moot because the CPUC mitigated these risks through establishing cost responsibility and recovery from all departing customers for above-market costs through the power charge indifference adjustment ("PCIA"). Since the customer is responsible for this obligation, and not the new load serving entity ("LSE"), the utility will be made whole for their outstanding PPAs. Additionally, CPUC Resolution E-4907 (2018) creates a minimum of one-year notice with meet and confer obligations between the CCA and IOU to determine resource adequacy requirements before a CCA can launch or expand service to include a new community. The IOU's concerns that they are now the provider of last resort ("POLR") but rules for POLR don't exist yet should also be dismissed. The risk of being the POLR and needing to serve customers returned from another LSE is covered under the CPUC's bond posting requirement pursuant to Cal. Pub. Util. Code 394.25(e) and implemented in the recent Decision 18-05-022. This posting includes amounts for procurement costs and administrative per-customer costs. The IOU concerns about existing-PPA debt equivalency are mitigated through departing load carrying the PCIA responsibility with them to other LSEs. The risk of future-PPA debt equivalency is also reduced as the bundled customer load decreases due to departing load. The additional wildfire costs and risks should be mitigated through the passage of Assembly Bill 1054 (2019) and the eventual restructuring plan resulting from PG&E's bankruptcy proceedings.

Respectfully submitted,

/s/ Daniel Settlemyer

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October 3, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION OF
THE STATE OF CALIFORNIA

Application of Marin Clean Energy for Approval of its Multifamily Whole Building Program under the Energy Savings Assistance Program 2021-2026	Application 19-11-___ (Filed November 4, 2019)

APPLICATION OF MARIN CLEAN ENERGY FOR APPROVAL OF ITS MULTIFAMILY WHOLE BUILDING PROGRAM UNDER THE ENERGY SAVINGS ASSISTANCE PROGRAM 2021-2026

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November 4, 2019

TABLE OF CONTENTS

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Marin Clean Energy for Approval of its Multifamily Whole Building Program under the Energy Savings Assistance Program 2021-2026	Application 19-11-___ (Filed November 4, 2019)

APPLICATION OF MARIN CLEAN ENERGY FOR APPROVAL OF ITS MULTIFAMILY WHOLE BUILDING PROGRAM UNDER THE ENERGY SAVINGS ASSISTANCE PROGRAM 2021-2026

I. INTRODUCTION

Marin Clean Energy ("MCE") respectfully submits this application for approval of MCE's Multifamily Whole Building ("MFWB") Program under the Energy Savings Assistance ("ESA") program for Program Years ("PY") 2021-2026 ("Application"). ESA is a statutorily established program that provides home weatherization services to qualifying low-income customers. This Application is being submitted in compliance with Decision ("D.") 16-11-022, which approved MCE's Low-Income Families and Tenants ("LIFT") Pilot Program ("LIFT Pilot") to provide energy efficiency ("EE") upgrades to both in-unit and common areas of low-income multifamily dwellings, including the installation of heat pumps.[1]

D.16-11-002 also directed MCE to "use the Application process if it elects to extend the LIFT pilot on a more permanent basis in [this] next program cycle."[2] Included with this Application is the *Testimony of MCE Regarding its Application for Approval of its Multifamily Whole Building Program Under the Energy Savings Assistance Program 2021-2026* ("MCE Testimony"). The MCE Testimony follows the California Public Utilities Commission's

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[1] *Decision on Large Investor-Owned Utilities' California Alternate Rates for Energy (CARE) and Energy Savings Assistance (ESA) Program Applications* ("D.16-11-022"), filed on November 21, 2016, at Ordering Paragraph ("OP") 147.
[2] D.16-11-022 at pp. 390-391.

("Commission" or "CPUC") directive in its *Decision Issuing Guidance to Investor-Owned Utilities for California Alternate Rates for Energy/Energy Savings Assistance Program Applications for 2021-2026 and Denying Petition for Modification* ("Guidance Decision").[3] Because MCE is only seeking to become a Program Administrator ("PA") for the MFWB Program, the MCE Testimony focuses mainly on the specific requirements described in the MFWB section of the Guidance Decision.[4] However, the MCE Testimony also includes information from other sections of the Guidance Decision where relevant and helpful.

II. SUMMARY OF APPLICATION AND REQUESTS

MCE proposes to build upon the successes and lessons learned from the LIFT Pilot and expand its reach with a new LIFT 2.0 Program, developed under the umbrella of the ESA MFWB program. LIFT 2.0 specifically addresses the Commission's mandate for deeper savings and innovative program designs for the low-income multifamily sector.[5] LIFT 2.0 was developed based on community feedback and incorporates tangible recommendations and lessons learned from MCE's LIFT Pilot. While the details of program design and delivery will be developed through the third-party solicitation process as envisioned by the Guidance Decision,[6] MCE is proposing several "cornerstones" of program delivery in this Application. These activities are specifically designed to address the obstacles observed in the low-income multifamily EE space and thereby will accelerate program adoption.

Specifically, MCE requests Commission approval of MCE's Application for its LIFT 2.0 Program, including the activities and proposed budgets as highlighted below, as soon as practical.

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[3] D.19-06-022 filed on June 28, 2019. The Decision entails three documents: (1) the Decision; (2) Attachment A: Guidance Document for the ESA and CARE Program Budget Applications for PYs 2021-2026, and (3) Attachment B: Excel templates.
[4] D.19-06-022, Attachment A at pp. 20-23.
[5] D.19-06-022 at p. 9.
[6] *Id.*

1. A third-party designed and implemented MFWB program as directed by D.19-06-022,[7] and MCE's proposed solicitation process and timeline;
2. A total budget of $10,603,955 over six years (2021 – 2026) to achieve the following goals:
    - Average annual per unit energy savings of 474 kilowatt-hours ("kWh"), 0.13 kilowatts ("kW") and 59.67 therms, not including fuel substitution measures;
    - Target whole building and in-unit measures at 80 properties and approximately 4,400 units; and
    - Increase the average overall reported tenant satisfaction with health, comfort and safety metrics when comparing pre-treatment to post-treatment results;
3. MCE's program delivery cornerstones, which are based on the obstacles observed in the low-income multifamily EE space, including:
    - Adjust the income eligibility threshold to 60% area median income ("AMI") to account for regional cost of living and to allow for more streamlined income verification processes;
    - Layer program offerings through MCE's Single Point of Contact ("SPOC") model to streamline customer experiences;
    - Treat naturally occurring affordable housing ("NOAH") properties while maintaining affordability;
    - Join with local governments and other community organizations as trusted messengers to reach vulnerable customer groups;
    - Offer innovative EE measures to be determined with third-party implementers,

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[7] *Id.*

including fuel switching components such as heat pumps, as well as those that can ease the adoption of time of use ("TOU") rates such as smart thermostats and grid-connected water heaters;

- Provide flexibility to multifamily building owners in the choice of contractors and installed equipment;

4. MCE's high-level plan for carrying out program evaluation, measurement and verification ("EM&V"); and
5. Continued local MCE administration of the LIFT 2.0 Program.

Support for each of the above requests is detailed in the MCE Testimony and the sections below.

III. BACKGROUND

MCE was established in 2010 as the first operating Community Choice Aggregator ("CCA") in California and serves 34 communities across Marin County, Contra Costa County, Napa County, and Solano County.

MCE has developed and administered general market (i.e., non-income qualified) EE programs since 2012.[8] Many of MCE's general market EE programs utilize third-party solicitations to request innovative program designs, take advantage of EE market expertise, and drive innovation in MCE's EE portfolio. MCE currently administers residential multifamily EE programs for non-income qualified customers as part of its approved ten-year Business Plan.[9] MCE's Multifamily Energy Savings ("MFES") program provides multifamily buildings with complimentary home energy assessments, no-cost technical assistance, low-cost loans and

[8] *Decision Enabling Community Choice Aggregators to Administer Energy Efficiency Programs* ("D.14-01-033"), filed January 23, 2014.
[9] *Decision Addressing Energy Efficiency Business Plans* ("D.18-05-041"), filed on June 5, 2018.

complimentary energy and water direct install measures for tenant units. MFES has been promoting EE in multifamily settings since 2012 and has a strong history of serving income-qualified properties.

Due to the large percentage of low-income properties participating in MCE's general market MFES program, MCE proposed the LIFT Pilot program under the investor-owned utilities ("IOUs") ESA program and budget applications in 2015.[10] The Commission approved MCE to administer its LIFT Pilot for two years in November 2016 in D.16-11-022.[11] In September 2019, MCE received approval to extended the LIFT Pilot timeline through the current ESA program cycle.[12]

Since its launch in October 2017, the LIFT Pilot has met or exceeded the expectations established at the onset of the Pilot.[13] Most notably, the LIFT Pilot has resulted in

- enrollment of 1,163 units comprising 21 properties;
- 130 heat pump reservations with 57 installations;
- high success in reaching hidden communities;
- 82% satisfaction report from tenants; and
- successful cross-promotion and enrollment in other available programs through MCE's SPOC model.[14]

In the Decision approving the LIFT Pilot, the Commission stated, "MCE shall use the

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[10] A.14-11-007, *Testimony of Marin Clean Energy Regarding a Proposed Low-Income Energy Efficiency Pilot Program for the Program Years 2015-2017*, filed on April 27, 2015.
[11] D.16-11-022 at Ordering Paragraph ("OP") 190.
[12] MCE Advice Letter 38-E, *Request for Timeline Only Extension of Marin Clean Energy's Low-Income Families and Tenants Pilot*, filed on September 11, 2019.
[13] MCE established metrics to track the status of the LIFT Pilot in MCE AL 23-E and 23-E-A, filed on April 6, 2017 and July 20, 2017 respectively.
[14] MCE submitted an interim report on the LIFT Pilot program in April of 2019, providing additional details on the status, key successes and lessons learned from Pilot implementation to date.

Application process if it elects to extend the LIFT Pilot on a more permanent basis in the next program cycle."[15] This is the relevant Application in which MCE is electing to extend the LIFT Pilot.

IV. LEGAL AND POLICY FRAMEWORK

The ESA Program is mandated by Public Utilities Code Section 2790(a), which reflects a legislative "policy of reducing energy-related hardships facing low-income households."[16] Public Utilities Code Sections 739.1 and 739.2 establish the California Alternate Rates for Energy ("CARE") program. The Commission authorized the low-income rate assistance programs in D.89-07-062 and D.89-09-044. Assembly Bill ("AB") 1890 was passed in 1996, establishing the framework for deregulating the California energy industry. Public Utilities Code Section 382, which was part of that bill, addresses funding for the ESA and CARE programs.

The California legislature provided CCAs a right to administer EE programs in Public Utilities Code Section 381.1. CCAs also have an obligation to provide EE programs because they are load-serving entities ("LSEs") and because EE is at the top of the loading order for generation resources under California state policy.[17] MCE must therefore be able to fully leverage EE as a generation resource. The Commission recognized the need for CCAs to administer EE programming in approving MCE's last EE Business Plan, even where there was the potential for overlapping programs with IOUs.[18]

Accordingly, MCE must have equal access to ESA Program funding in order to effectively

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[15] D.16-11-022 at p. 387.
[16] Cal. Pub. Util. Code § 2790(a).
[17] Cal. Pub. Util. Code § 454.5(b)(9)(C) indicates: "[t]he electrical corporation shall first meet its unmet resource needs through all available energy efficiency and demand reduction resources that are cost effective, reliable, and feasible." See also State of California Energy Action Plan I, 2003 at p. 4 (defining a loading order with energy efficiency as the primary resource); and the Energy Efficiency Policy Manual at p. 1 (noting energy efficiency is a procurement resource and first in the loading order).
[18] *See,* D.18-05-041 at p. 111.

provide comprehensive EE programming to its low-income customers on par with the IOUs regardless of potential overlap. The Commission further recognized the value and legitimacy of CCA administered ESA programming in approving MCE's LIFT Pilot and directing MCE to come back for additional funding via this next ESA program cycle.[19]

Additional statewide laws and policies further support Commission approval of MCE's Application to expand EE offerings in the low-income multifamily sector. First, Public Utilities Code Section 382(e) states "[t]he commission shall, by not later than December 31, 2020, ensure that all eligible low-income electricity and gas customers are given the opportunity to participate in LIEE ["low income energy efficiency"] programs, including customers occupying apartments or similar multiunit residential structures." Second, Senate Bill ("SB") 350 requires the state to reduce greenhouse gas ("GHG") emissions by 40% below 1990 levels.[20] The bill also requires the California Energy Commission ("CEC") and the CPUC to create a plan by 2023, to achieve statewide *doubling* of EE savings and demand reductions by 2030.[21] Third, AB 3232 further requires the CPUC, CEC, California Air Resources Board ("CARB") and the California Independent System Operator ("CAISO") to specifically assess the potential for the State to reduce GHG emissions associated with the supply of energy to both the commercial and residential building stock by at least 40% below 1990 emissions levels by 2030.[22] MCE's LIFT 2.0 Program will assist the Commission and the State to achieve these ambitious and worthy EE, building de-carbonization, low-income participation, and GHG reduction goals.

LIFT 2.0's targeted offerings also advance the CPUC's Environmental and Social Justice

[19] D.16-11-022 at p. 387.
[20] Cal. Pub. Util. Code § 454.52(a)(1)(A).
[21] Cal. Pub. Res. Code § 25310(c)(1).
[22] Cal. Pub. Res. Code § 25403 (a).

("ESJ") Action Plan, which emphasizes the need to advance equity in programs and policies for ESJ Communities. [23] LIFT 2.0 is well positioned to advance these ESJ goals by offering to serve the traditionally underserved multifamily low-income building sector.

In summary, MCE's LIFT 2.0 Program is offered pursuant to existing ESA legislation, a CCA's right to administer EE programming, a CCA's obligation to utilize EE in serving load, and furthers numerous State policy objectives such as GHG reduction, building electrification and the ESJ Action Plan. As such, the Commission has the authority to grant MCE the right to administer LIFT 2.0 as a permanent ESA MFWB program.

V. MCE'S LIFT 2.0 PROGRAM DISCUSSION

LIFT 2.0 will incorporate the successful aspects of the LIFT Pilot while expanding the offering to specifically address remaining obstacles in the income-qualified multifamily space. MCE outlines its main requests for Commission approval and LIFT 2.0 Program design proposals below. Additional detail can be found in the MCE Testimony.

A. The Commission should approve LIFT 2.0 as a third-party designed and implemented program as envisioned by the Guidance Decision

LIFT 2.0 complies with the Commission's Guidance Decision and its direction to select a third-party entity to design and implement the MFWB program.[24] Third-party implementation is an effective program delivery model utilized frequently in ratepayer-funded EE programs, which acknowledges that different vendors bring unique experience in specific target markets or technology areas. While not explicitly required to do so, MCE utilizes the third-party solicitation

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[23] Environmental and Social Justice Action Plan, Version 1.0, February 2019, *available at* https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/About_Us/Organization/Commissioners/Martha_Guzman_Aceves/Env%20and%20Social%20Justice%20ActionPlan_%202019-02-21.docx.pdf at p.6.
[24] D.19-06-022 at p.9.

process in its general EE programming because MCE understands the value in utilizing private market expertise for program design and implementation.[25] MCE further believes that utilization of third-party implementers is consistent with MCE's obligation to pursue cost-effective EE programs to meet its customer's procurement needs.[26]

By utilizing third-party implementers in the LIFT 2.0 Program, MCE, as the PA, will be able to effectively focus on independent program oversight, budget management, evaluation, EM&V, and reporting of program impacts to the Commission. On the other hand, MCE's program implementers are well positioned to deliver projects and generate program impacts, grow a network of qualified contractors or installers, lead outreach to stakeholders, and review targeted technologies and their specifications. Allowing third-party implementers to focus on these activities will maximize cost effectiveness. For these reasons, the Commission should approve MCE's MFWB program as a third-party designed and implemented program.

MCE elaborates on its proposed solicitation processes and timeline in the MCE Testimony and proposes the following specific solicitation schedule:

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[25] *See*, *Decision Providing Guidance for Initial Energy Efficiency Rolling Portfolio Business Plan Filings* ("D.16-08-019"), filed on August 25, 2016, at pp. 69 – 70 (upholding third party requirements for utilities).
[26] A.17-01-013, *Final Reply Comments of Marin Clean Energy on Energy Efficiency Business Plans* ("MCE Final Reply Comments"), filed on October 13, 2017, at p. 5 (*citing, Decision Enabling Community Choice Aggregators to Administer Energy Efficiency Programs* ("D.14-01-033"), filed on January 23, 2014, OP 3, at p. 50 (Applying IOU cost- effectiveness standards to CCAs); and *Decision Establishing Energy Efficiency Savings Goals and Approving 2015 Energy Efficiency Programs and Budgets* ("D.14-10-046"), filed on October 24, 2014, at pp. 109-110 (Setting a TRC ratio of 1.25 for IOUs and CCAs)).

Task	Time after Program Approval
Issue Solicitation	4 weeks
Vendor Selection	3 months
Executed Contracts	5 months
Stakeholder Workshop on Program Design	6 months
Launch Program	7 months

B. The Commission should approve MCE's budgets and goals for LIFT 2.0 and make the appropriate funding available for the program cycle 2021-2026

The proposed program budget for LIFT 2.0 is $10,603,955 over six years (2021 – 2026). Annual budget details and the excel budget template as specified in the Guidance Decision are provided in MCE's Testimony.

This funding will allow MCE to pursue the following goals:

- **Energy savings targets:**[27] annual, per unit savings of 474 kWh, 0.13kW and 59.67 therms, not including fuel substitution measures;[28]
- **Household targets:** target whole building and in-unit measures at 80 properties and approximately 4,400 tenant units;
- **Health, safety and comfort improvements:** increase the average overall self-reported tenant satisfaction with health, comfort and safety metrics when comparing pre-treatment results to post-treatment results.

MCE requests that the Commission approve its proposed LIFT 2.0 budgets and direct

[27] Because the measure list for LIFT 2.0 will be finalized in partnership with the third-party implementer, these targets are subject to change.
[28] While savings are averaged on a per unit basis, they include any savings from whole building or common area measures, averaged by the number of units in a particular property. Per unit average savings are more comparable than per property average savings due to variations in property size.

PG&E to transfer MCE's annualized LIFT 2.0 Program budget by January 15 of each year, similar to the process adopted in D.14-01-033 and further refined in R.13-11-005 for MCE's administration of general market EE funding.[29]

C. The Commission should approve MCE's proposed program design and delivery strategies, which specifically address obstacles to implementing energy efficiency for income-qualified customers in multifamily buildings and which will accelerate Program adoption

Tenants and property owners of income-qualified multifamily properties face myriad obstacles for accessing and engaging in available EE programs. To accelerate MFWB program adoption, LIFT 2.0's delivery strategies are specifically designed to address the obstacles MCE encountered in servicing income-qualified multifamily properties under the LIFT Pilot.

Further, MCE gathered feedback from various different stakeholder groups on its LIFT 2.0 Program proposal. MCE discussed the proposal with advocacy groups with a longstanding engagement in the IOU's ESA programs, such as Energy Efficiency for All. Furthermore, MCE presented the LIFT 2.0 Program proposal to MCE's Community Power Coalition, a group of diverse advocacy organizations that addresses issues of equity, sustainability, environmental justice and disadvantaged communities ("DACs"). Finally, the LIFT 2.0 Program proposal was presented to and discussed with MCE's board of directors, comprised of elected officials from the local governments that comprise MCE's service area. Through its experience and investigation, MCE has identified the following obstacles to EE program implementation in the income-qualified multifamily space that are being addressed under LIFT 2.0.

[29] D.14-01-033 at pp. 17, 37.

i. LIFT 2.0 addresses customer acquisition barriers

One of the major hurdles of current EE low-income multifamily programs relates to customer acquisition, especially in regards to identifying and enrolling low-income customers in NOAH properties.[30] At the same time, NOAH properties constitute the majority of low-income multifamily buildings and units in MCE's service territory.[31] In D.16-11-022, the Commission recognized the challenge and difficulties of reaching a competitive market sector for privately owned, non-deed restricted, multifamily housing for participation in ESA programs.[32]

Unlike existing ESA Programs administered by the IOUs, which focus primarily on deed-restricted properties,[33] LIFT 2.0 will serve all eligible low-income multifamily properties. NOAH properties are challenging to identify, as these properties are not included in government datasets as low-income housing. However, MCE's network of local government agencies, community organizations, and EE implementers have a long-standing history in working with this customer segment and are knowledgeable about how to best identify and approach them. Granting MCE the authority to administer LIFT 2.0 will further the Commission's objective of identifying NOAH properties for participation in ESA programs.[34] LIFT 2.0 also includes a number of measures to ensure that EE upgrades implemented under the program do not negatively impact affordability in NOAH properties. These measures include requiring landlord, tenants and MCE to sign enforceable affidavits that limit rent increases and evictions, as well as establish additional reporting and monitoring provisions.

[30] NOAH includes residential rental properties that maintain low rents without federal subsidy or deed restrictions
[31] Based on TRC Memorandum for PG&E "ESA Multifamily Common Area Non-Deed Restricted Opportunity Analysis– 2018 Annual Report Filing Final Analysis."
[32] D.16-11-022 at p. 180.
[33] PG&E ESA CAM Implementation Plan at p.18. See at https://www.pge.com/tariffs/assets/pdf/adviceletter/GAS_3943-G.pdf
[34] *See*, D.16-11-022 at pp. 189-190.

Another customer acquisition barrier is the need to earn the trust of vulnerable and hard-to-reach populations and to address concerns regarding the sharing of personal information (e.g., income verification documentation). In order to address this customer acquisition barrier, MCE will work with local government partners such as city and county housing agencies as marketing, education and outreach ("ME&O") partners to make the first touch with building owners. This collaboration places credible organizations at an early point of engagement, which is a crucial period for gaining customers' trust. MCE is already successfully partnering with local governments on targeted customer outreach. For example, MCE is partnering with the Aging and Adult Services Division of the Marin Health and Human Services to deliver health and safety related measures into properties with large populations of aging and elderly residents. Additionally, MCE has also been working with the Contra Costa County's health program to identify properties with a high incidence of asthma and provide health services and EE upgrades through a single program. MCE proposes to deepen this coordination under LIFT 2.0 and to identify additional specific outreach channels with other local governments.

ii. LIFT 2.0 addresses program eligibility barriers

Once a customer has been identified and approached, the next barrier to overcome are the challenges associated with current ESA Program income eligibility thresholds and processes. To address these challenges, LIFT 2.0 seeks to move beyond the income eligibility threshold of 200% Federal Poverty Guideline ("FPG"), which CARE and ESA presently use. Instead, MCE proposes to use 60% AMI as the income eligibility threshold for LIFT 2.0, thereby aligning the program with other EE and clean energy programs for income qualified customers.

MCE believes that revising the income eligibility threshold for ESA participation is within the Commission's discretion and is appropriate here, where significant barriers exist in reaching vulnerable populations in multifamily buildings in the Bay Area because of the extraordinarily high cost of living. The Commission initially tied the ESA income eligibility threshold (of the then-called "low-income weatherization" or "LIW" program) to the statutorily mandated income threshold for CARE in Resolution E-3254, adopted January 21, 1992.[35] In that Resolution, the Commission adjusted the income limitation for the LIW program (with some exceptions) "to match the CARE program to reduce customer confusion."[36] In Resolution E-3439, adopted on February 23, 1996, the Commission held that all utilities should use the (then) 150% FPG for CARE and LIW programs, but also provided an income eligibility threshold of 80% of *county* median income for "community type or block weatherization programs… in a specifically designated low income area with Commission approval."[37]

Two important conclusions can be drawn form these Resolutions regarding the CPUC's authority to modify ESA eligibility criteria. First, Resolution E-3254 established a link between ESA and CARE eligibility for the express purpose of reducing customer confusion between the two programs. For LIFT 2.0, where MCE will provide SPOC service, customers will be guided through the process of eligibility screening. Further, various other California programs for low-income customers have adopted income eligibility thresholds that are based on AMI, such as the Solar on Multi-family Affordable Housing ("SOMAH") and Self-Generation Incentive Program ("SGIP") Equity programs. Hence, modifying LIFT 2.0 to 60% AMI would not cause customer confusion but would instead ease customer participation by aligning program eligibility requirements. Second, as noted above, the Commission has already exercised its discretion to depart from CARE eligibility thresholds for ESA/LIW programming in adopting certain

[35] *Order Requiring Energy Utilities to Revise Income Limits for the California Alternate Rates for Energy (CARE) and for the Low-Income Weatherization Program* ("Resolution E-3439"), issued February 23, 1996 at p.1 (*citing* Resolution E-3254, adopted January 21, 1992)
[36] Resolution E-3439 at p. 1.
[37] Resolution E-3439 at p. 2.

community specific programs, just as MCE requests the Commission do with its community focused LIFT 2.0 MFWB proposal.

Revising the income eligibility threshold to 60% AMI will allow LIFT 2.0 to serve in need customers that would otherwise be stranded between the existing ESA offerings and general market EE programs. MCE's service territory, which spans four counties, is home to thousands of low-income households who struggle to make ends meet, but many of them are ineligible for the IOU's ESA programs under the current income eligibility criteria.

Furthermore, MCE proposes a series of additional steps to streamline the income eligibility verification process. For example, MCE plans to allow enrollment into LIFT 2.0 without requiring additional income verification for customers enrolled in the SOMAH and SGIP Equity programs, as well as customers enrolled in the CARE rate. MCE will also offer customized assistance through the SPOC to guide customers through the LIFT 2.0 eligibility verification process.

iii. LIFT 2.0 addresses program complexities

Participants in existing EE programs often criticize the complex program requirements and processes that can prevent participation in programs outright. Additionally, many programs are available to tenants and property owners of low-income multifamily properties, which can be confusing to many customers. The LIFT 2.0 Program addresses complexity barriers by leveraging MCE's proven SPOC model, which MCE has used successfully on all of its programs for several years. To navigate program complexities, MCE's SPOC not only guides customers through the program processes, but also provides technical assistance to optimize the measure mix. Furthermore, the SPOC helps property owners and managers leverage other EE, clean energy and transportation program offerings aimed at low-income multi-family buildings.

iv. LIFT 2.0 empowers customers

MCE's experience under the LIFT Pilot has shown that property owners strongly prefer to have the ability to select specific equipment and contractors of their choosing. While this is not a standard procedure under the ESA Program in general, MCE proposes the Commission allow property owners the flexibility to choose both contractors and equipment under LIFT 2.0. This will further empower program participants' self-sufficiency and engagement in the program. Along those same lines, LIFT 2.0 strives to work with property owner's timelines and plan EE upgrades around larger property remodel projects that may be planned or ongoing.

v. LIFT 2.0 addresses the obstacles of heat pump installations

One of the major obstacles to heat pump installation is the high customer cost share after incentives and/or rebates, which may also include ancillary project costs such as upgrades to the electrical panel. Leveraging other funding sources via the SPOC model will help lower this cost barrier.

vi. LIFT 2.0 supports customers in the use of innovative EE technologies and in the transition to TOU rates

MCE will promote innovative EE technologies under LIFT 2.0, including, but not limited to, fuel substitution and residential demand response ("DR") technologies. Fuel substitution measures have the potential to greatly improve resident's health, safety and comfort. DR services present a way for customers to take control over their energy use and add an additional value stream to their property upgrades.

Surveys conducted with LIFT Pilot participants indicated a general lack of knowledge regarding the benefits and operation of heat pumps. To address this, the SPOC will provide in-person consultation and online tutorials to LIFT 2.0 tenants regarding heat pump operation. While engaging with program participants, the SPOC will also educate tenants and property owners on the use and benefits of DR-enabled technologies and the impacts of the impeding transition to TOU rates.

vii. LIFT 2.0 includes workforce education and training

Under the LIFT Pilot, MCE recognized that one of the main challenges to promoting heat pumps is the dearth of qualified installation contractors. To address this issue, LIFT 2.0 will provide a home performance education component targeting the local contractor population. Contractor education will focus on, but is not limited to, increasing the pool of contractors qualified to install heat pumps. This is consistent with MCE's mission "to address climate change by reducing energy related greenhouse gas emissions through renewable energy supply and energy efficiency at stable and competitive rates for customers while providing local economic and workforce benefits."[38]

MCE has thoughtfully and methodically applied lessons learned from its LIFT Pilot to develop a more effective and efficient LIFT 2.0 Program. The Commission should approve MCE's LIFT 2.0 Program because it is consistent with the Commission's stated focus on innovative program designs for the multifamily sector, including a low-income MFWB EE third-party program.[39]

D. The Commission should approve MCE's high-level plan for carrying out EM&V activities

MCE will contract with an independent third-party to perform EM&V and process evaluations and has set aside four percent of total budget for this task. The exact evaluation process for the new round of ESA Programs has yet to be determined. However, MCE presents its high-level plan for carrying out EM&V activities below.

- **EM&V Objective 1: Verify Program Progress towards Key Success Metrics and Enable Real-Time Program Improvement** - MCE will track program performance based

[38] MCE Mission. Available at https://www.mcecleanenergy.org/.
[39] D.19-06-022 at p. 9.

on a set of key success metrics, including measure level and participant data. Data will be collected in real time and analyzed at critical milestones to determine whether program modifications are necessary.

- **EM&V Objective 2: Quantify the Effect of the Revised Eligibility Criteria and the Targeted Outreach Strategies -** MCE will particularly examine the impact of the updated income eligibility requirements and the revisions to the income verification process on program participation.
- **EM&V Objective 3: Develop a List of Key Accomplishments, Best Practices and Lessons Learned -** MCE will develop a list of program design recommendations and challenges through interviews with program participants, implementation staff, and partners.

E. The Commission should authorize MCE to administer its LIFT 2.0 Program as a local program

As noted above, the Commission approved MCE to administer the LIFT Pilot as a locally run program in MCE's service area in 2016 and explicitly directed MCE to use this Application process to extend the LIFT Pilot on a more permanent basis.[40] MCE has proven its success in implementing the LIFT Pilot, and is uniquely positioned to continue the implementation of multifamily low-income EE programs. First, MCE can build upon the lessons learned from the LIFT Pilot to specifically address the remaining obstacles encountered by income-qualified residents in multifamily properties. Second, MCE's small size compared to utility PAs allows MCE to be more nimble, responsive, targeted, and innovative in its approach to programs. Finally,

[40] D.16-11-022 at p. 387.

MCE's local governance structure and connection to its local community allow MCE to incorporate community feedback into the development of its programs, and to leverage local government partner agencies as outreach mechanisms and for program leveraging. Customer outreach strategies, especially those targeting low-income customers, are best implemented on a local level through trusted messengers to overcome mistrust among vulnerable populations.

MCE recognizes that the Guidance Decision recommends that *the IOUs* propose a statewide-administered MFWB program with a single implementer.[41] As an initial matter, MCE believes this direction was not directed at CCAs or other non-IOU implementers. This is evidenced by the Commission's approval of MCE's LIFT Pilot and its invitations to apply for additional funding to extend LIFT.[42] For the reasons discussed above, MCE finds that program implementation for downstream EE programs, especially those dealing with vulnerable populations, is most successful when implemented at the local level. Locally administered programs can target the specific local needs and challenges, as well as using local agencies as outreach partners. The hurdles encountered under the LIFT Pilot discussed above in Section V. C. can best be addressed with a local program that provides tailored customer support utilizing local community contacts.

Further, D.16-08-019 generally expressed a preference for implementing statewide-administered programs for *upstream and midstream programs*, with a focus on market transformation.[43] The commission ruled that "upstream and midstream programs, where partners are manufacturers, retailers, or distributors, <u>but not contractors, installers, or individual customers,</u> as well as market transformation efforts, are appropriate to be handled on a statewide basis."[44]

[41] D.19-06-022 at p. 20.
[42] D.16-11-022 at p. 387.
[43] D.16-08-019 at pp. 57-59.
[44] D.16-08-019 at pp. 51-52 and Conclusion of Law ("COL") 50.

Because the ESA MFWB program involves direct and targeted outreach to low-income multifamily building owners, managers and tenants on an individualized basis, they are not midstream or upstream programs.

Because MCE is uniquely positioned to service its customers, the Commission should approve MCE to be the MFWB local administrator for its service area.

VI. STATUTORY AUTHORITY AND COMPLIANCE WITH THE COMMISSION'S RULES OF PRACTICE AND PROCEDURE

A. Statutory and Other Authority – Rule 2.1

MCE is applying to administer its LIFT 2.0 ESA MFWB Program pursuant to Public Utilities Code Section 2790(a), MCE's authority to administer EE programs pursuant to Public Utilities Code Section 381.1(a)-(d), and the Commission's direction in D.16-11-022 that MCE "use the Application process if it elects to extend the LIFT pilot on a more permanent basis in [this] next program cycle."[45]

B. Legal Name of Applicant and Related Information - Rule 2.1(a)

The legal name of the Applicant is Marin Clean Energy. MCE's principal place of business is San Rafael, California. Its address is 1125 Tamalpais Avenue, San Rafael, CA 94901. MCE is a joint powers authority formed under the laws of California.

[45] D.16-11-022 at p. 387.

C. Correspondence and Communications - Rule 2.1(b)

All correspondence and communications regarding this application should be addressed to:

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D. Categorization – Rule 2.1(c)

MCE proposes that this Application be categorized as a "ratesetting" proceeding pursuant to Rule 7.1(e)(2) of the Commission's Rules of Practice and Procedure because it does not clearly fit into any of the categories as defined by Rules 1.3(a), 1.3(d), and 1.3(e). MCE's Application does not meet the definition of adjudicatory in Rule 1.3(a) because it is neither an enforcement investigation nor a complaint.

MCE's Application does not clearly fit the definition of quasi-legislative under Rule 1.3(d) because it has components specific to MCE. The specific components include the request for funding for MCE's own ESA MFWB program. Since this application contains components other than quasi-legislative, it is not clearly a quasi-legislative proceeding under Rule 1.3(d).

Categorization of this Application as "ratesetting" under Rule 7.1(e)(2) is consistent with how IOU ESA applications are categorized and how the Commission has previously categorized similar EE funding applications.[46]

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[46] A.17-01-013, *Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge*, filed on April 14, 2017, at p. 14.

E. Need for Hearing - Rule 2.1(c)

MCE has endeavored to provide a sufficient record via the Application materials to obviate the need for evidentiary hearings. MCE does not recommend hearings at this time. If the need for hearings arises, MCE requests that the resulting hearing schedule allow the Commission to render a final decision on this Application with sufficient time to start implementing the Lift 2.0 MFWB Program at the start of the ESA 2021-2026 program cycle.

F. Proposed Schedule – Rule 2.1(c)

MCE concurs with the preliminary schedule provided in the Guidance Decision with a goal for a final decision that allows implementation of ESA programs by 2021:[47]

File Application	October, 2019
Protests/Replies Due	November, 2019
Reply to Protests	December, 2019
Prehearing Statements/Conference	Winter 2020
Scoping Memo	Spring 2020
Discovery	Spring 2020
Intervenor Testimony/Deadline for motion on hearings	Spring 2020
Rebuttal Testimony	Summer 2020
Hearings/workshops & Discovery cut off	Summer 2020
Opening Briefs	Summer 2020
Reply Briefs	Summer 2020
Proposed Decision	TBD
Comments/Reply Comments on PD	TBD
Final Decision	Winter 2020

G. Issues to be Considered – Rule 2.1(c)

MCE requests the Commission approve MCE's Application for a MFWB Program under the ESA 2021-2026 program to enable MCE to continue serving low-income multifamily

[47] D.19-06-022, Attachment A at p. 36.

properties with weatherization, EE, health, safety and comfort upgrades. MCE also requests the Commission take action to address the following issues:

- MCE's proposed LIFT 2.0 third-party designed and implemented MFWB program;
- MCE's proposed LIFT 2.0 total budget of $10,603,955 over six years (2021 – 2026);
- MCE's proposed LIFT 2.0 goals;
- MCE's program delivery strategies as described in its Application, including but not limited to, a 60% AMI income eligibility threshold;
- MCE's high-level plan for EM&V activities; and
- Continued local MCE administration of the LIFT 2.0 Program.

H. Articles of Incorporation - Rule 2.2

MCE is a CCA operating as a joint powers authority ("JPA") organized under California law. MCE commenced operations as a JPA on December 19, 2008. MCE is engaged in the provision of electric generation services under the authority granted in Public Utilities Code Section 366.2 and general market EE programs under the authority granted in Public Utilities Code Section § 381.1. A copy of MCE's current Amended Joint Powers Agreement, executed April 21, 2016 is available on MCE's website.[48]

I. Rule 3.2 (a)-(d) is inapplicable to MCE's Application

The Rule 3.2 requirements do not apply to this Application because MCE does not request authority to increase rates or to implement changes that would result in increased rates. IOU's perform revenue collection for ESA programs and typically provide the materials called for under Rule 3.2 in their ESA applications. As discussed above in Subsection VI.C (Categorization - Rule 2.1(c)), MCE is not in a position of revenue collection for ESA programs. Thus it is inappropriate for MCE to propose specific rate changes related to this Application. The only information called

[48] As of the date of this filing, the most recent Joint Powers Agreement is available at https://www.mcecleanenergy.org/wp-content/uploads/2016/06/JPA-Agreement-with-Amendment-10-on-4.21.16-24-Communities.pdf

for under Rule 3.2 that MCE can feasibly provide is not meaningful to a ratesetting decision in the context of ESA programs. Therefore, it is unreasonable to impose the requirements of Rule 3.2 on this Application. This is the approach followed in similar EE program proceedings.[49]

J. Notice and Service of Application

A copy of the Application and the MCE Testimony are being served on Administrative Law Judge MacDonald and on the parties of record in A.14-11-007 et.al.

K. List of Supporting Documents

MCE submits this Application along with its *Testimony of MCE Regarding its Application for Approval of its Multifamily Whole Building Program Under the Energy Savings Assistance Program 2021-2026* and the attachments thereto.

VII. CONCLUSION

MCE respectfully requests the Commission expeditiously approve this Application.

Respectfully submitted,

By: *Jana Kopyciok-Lande*

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November 4, 2019

[49] A.17-01-013, Application of Marin Clean Energy for Approval of its Energy Efficiency Business Plan, filed on January 17, 2017, at p. 31.

VERIFICATION

I, the undersigned, say:

I am an officer of Marin Clean Energy and am authorized to make this verification on its behalf. The statements in the foregoing *Application of Marin Clean Energy for Approval of its Multifamily Whole Building Program under the Energy Savings Assistance Program 2021-2026* are true of my own knowledge, except as to the matters which are herein stated on information and belief, and as to those matters, I believe them to be true.

I declare under penalty of perjury that the foregoing is true and correct. Executed at San Rafael, California this 4th day of November, 2019.

/s/ Dawn Weisz
DAWN WEISZ
Chief Executive Officer

MARIN CLEAN ENERGY

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Investigation on the Commission's Own Motion to Consider the Ratemaking and Other Implications of a Proposed Plan for Resolution of Voluntary Case filed by Pacific Gas and Electric Company Pursuant to Chapter 11 of the Bankruptcy Code, in the United States Bankruptcy Court, Northern District of California, San Francisco Division, In re Pacific Gas and Electric Corporation and Pacific Gas and Electric Company, Case No. 19-30088.	Investigation 19-09-016 (Filed September 26, 2019)

COMMENTS OF MARIN CLEAN ENERGY ON
ORDER INSTITUTING INVESTIGATION

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October 18, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Investigation on the Commission's Own Motion to Consider the Ratemaking and Other Implications of a Proposed Plan for Resolution of Voluntary Case filed by Pacific Gas and Electric Company Pursuant to Chapter 11 of the Bankruptcy Code, in the United States Bankruptcy Court, Northern District of California, San Francisco Division, In re Pacific Gas and Electric Corporation and Pacific Gas and Electric Company, Case No. 19-30088.	Investigation 19-09-016 (Filed September 26, 2019)

RESPONSE OF MARIN CLEAN ENERGY TO
ORDER INSTITUTING INVESTIGATION

Marin Clean Energy ("MCE") submits the following response to the *Order Instituting Investigation* filed September 26, 2019 ("OII"). Ordering Paragraph 4[1] allows non-PG&E entities to file responses no later than October 18, 2019.

I. INTRODUCTION

MCE, California's first community choice aggregator ("CCA"), is a not-for-profit public agency that began service in 2010 with the goals of providing cleaner power at stable rates to its customers, reducing greenhouse emissions, and investing in energy programs that support communities' energy needs. MCE is a load-serving entity serving approximately 1,000 MW peak load, providing electricity generation services to more than 1.1 million people in 34 communities across four Bay Area counties.

[1] OII at p. 13.

II. RESPONSE TO OII

MCE, along with many CCAs throughout the state, is devoting resources to and engaging in PG&E's bankruptcy case. MCE and its ratepayers have numerous interests that may be frustrated by the eventual restructuring plan that allows PG&E to exit bankruptcy. Pursuant to California law, PG&E is responsible for metering, billing and delivering electricity to MCE's customers, collecting payments from MCE's customers, and remitting these funds to MCE. MCE's continued operations and the provision of reliable electricity to its customers depend upon PG&E's regular remittance of revenue from MCE's customers to MCE. MCE also has a number of contracts with PG&E to provide power, resource adequacy, and other services. Finally, MCE's ratepayers are also PG&E ratepayers and may be exposed to increased rates or inappropriate cost allocation in the eventual restructuring plan. MCE intends to engage in this proceeding to protect those interests and supports the scope of the OII.

MCE is aware of both (1) PG&E's restructuring plan; and (2) the alternative plan, proffered by the Tort Claimants Committee and the Ad Hoc Committee of Senior Unsecured Noteholders. MCE is not supporting either plan at this time.

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I. CONCLUSION

MCE appreciates the opportunity to support the California Public Utilities Commission's examination of the restructuring plans and thanks President Batjer and Administrative Law Judge Allen for their thoughtful consideration of the issues.

Respectfully submitted,

/s/ Michael Callahan

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October 18, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Investigation on the Commission's Own Motion to Determine Whether Pacific Gas and Electric Company and PG&E Corporation's Organizational Culture and Governance Prioritize Safety.	Investigation 15-08-019 (Filed August 27, 2015)

REPLY COMMENTS OF THE PENINSULA CLEAN ENERGY AUTHORTY, MARIN CLEAN ENERGY, SAN JOSE CLEAN ENERGY, PIONEER COMMUNITY ENERGY AND SILICON VALLEY CLEAN ENERGY ON PROPOSALS TO IMPROVE SAFETY CULTURE OF PACIFIC GAS AND ELECTRIC COMPANY AND PG&E CORPORATION

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For the Peninsula Clean Energy Authority, Marin Clean Energy, San Jose Clean Energy, Pioneer Community Energy, and Silicon Valley Clean Energy

August 2, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Investigation on the Commission's Own Motion to Determine Whether Pacific Gas and Electric Company and PG&E Corporation's Organizational Culture and Governance Prioritize Safety.	Investigation 15-08-019 (Filed August 27, 2015)

REPLY COMMENTS OF THE PENINSULA CLEAN ENERGY AUTHORTY, MARIN CLEAN ENERGY, SAN JOSE CLEAN ENERGY, PIONEER COMMUNITY ENERGY, AND SILICON VALLEY CLEAN ENERGY ON PROPOSALS TO IMPROVE SAFETY CULTURE OF PACIFIC GAS AND ELECTRIC COMPANY AND PG&E CORPORATION

Pursuant to the Joint Assigned Commissioner's and Administrative Law Judge's Ruling on Proposals to Improve the Safety Culture of Pacific Gas and Electric Company and PG&E Corporation, issued June 18, 2019 (the "Ruling"), Peninsula Clean Energy Authority ("PCE"), Marin Clean Energy ("MCE"), San Jose Clean Energy ("SJCE"), Pioneer Community Energy ("Pioneer"), and Silicon Valley Clean Energy ("SVCE"), collectively the "Replying CCAs," respectfully submit the following reply to parties' opening comments filed on July 19, 2019.[1]

PCE is a Joint Powers Authority formed on February 29, 2016 by the County of San Mateo and each of the County's twenty incorporated cities. PCE currently serves approximately 300,000 customer accounts for the 765,000 residents and businesses in San Mateo County. MCE provides electricity service to approximately 470,000 customer accounts and more than 1 million residents and businesses in thirty-four member communities across four Bay Area counties including Napa, Marin, Contra Costa, and Solano. SJCE formed in September 2018 as the

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1 The Replying CCAs have given the undersigned authority to submit these reply comments on their behalf.

electricity service provider for residents and businesses in the City of San José, operated by the City's Community Energy Department. Governed by the City Council, SJCE serves over 300,000 residential and commercial electricity customers. SVCE is a Joint Powers Authority launched in April 2017 to promote decarbonization in its member communities. SVCE provides retail electric service to approximately 267,000 customer accounts in twelve cities and the unincorporated areas of Santa Clara County. Pioneer serves more than 86,000 customers in the cities of Auburn, Colfax, Lincoln and Rocklin, the town of Loomis and unincorporated Placer County. Collectively, the Replying CCAs serve over 1.4 million customer accounts which represent millions of Californian citizens and businesses.

Replying CCAs are customers of PG&E, as are Replying CCAs' customers. The proposals discussed in parties' opening comments would have direct and profound effects on Replying CCAs. Accordingly, the Replying CCAs appreciate the opportunity to provide this reply.

I. SUMMARY OF REPLYING CCAS' REPLY COMMENTS

In February, a number of community choice aggregators (the "Joint CCAs") filed comments in this docket.[2] The Joint CCAs argued that safety at PG&E can be increased by removing PG&E from the retail generation business and focusing PG&E as a "wires-only" company. To effectuate this outcome, the comments argued that the Commission should support increased local control of retail generation services through the formation of additional CCAs, the expansion of existing CCAs, and/or municipalization of utility services (including transmission and distribution resources). The Joint CCAs also argued that programs related to

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2 *See, Opening Comments of East Bay Community Energy, Peninsula Clean Energy Authority, Pioneer Community Energy, the City of San José on behalf of San José Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy Alliance*, Docket I.15-08-019 (February 13, 2019).

energy efficiency, demand response, and vehicle electrification should be moved to local control, so that PG&E may focus on improving the safety of its remaining transmission and distribution operations. The comments argued that in areas of the state that do not want to form a CCA or municipalize, the Commission should support a process to form or expand a public entity to take on the retail generation function from PG&E and operate as a residual buyer of resource adequacy requirements not procured by other load serving entities. In reply comments, the Joint CCAs also supported proposals to manage PG&E's distribution system as an open and transparent platform to support deployment of distributed energy resources, storage and other applications.[3]

In keeping with the Joint CCAs' prior comments, parties' opening comments submitted on July 19, 2019 continue to offer broad support for the expansion of public power options as a means of increasing safety at PG&E. For example, the California Municipal Utilities Association ("CMUA") cautions: "[t]he Commission must face the real possibility that PG&E is simply too large to be safely managed."[4] Likewise, South San Joaquin Irrigation District ("SSJID") observes that the primary concern at the heart of PG&E's failed safety culture is "its oversized service territory and the excessive number of layers in its management structure."[5] To remedy this, SSJID proposes to allow local public entities that are ready, willing and able to serve to take on additional responsibilities.[6]

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3 *See, Reply Comments of East Bay Community Energy, Marin Clean Energy, Monterey Bay Community Power, Peninsula Clean Energy Authority, Pioneer Community Energy, the City of San José on behalf of San José Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy Alliance*, Docket I.15-08-019 (February 28, 2019).

4 I.15-08-019, *Opening Comments of the California Municipal Utilities Association to the Joint Assigned Commissioner's and Administrative Law Judge's June 18, 2019 Ruling,* p. 4 (July 19, 2019) ("CMUA Opening Comments").

5 I.15-08-019, *Comments of South San Joaquin Irrigation District on Proposals to Improve Safety* Culture, p. 1 (July 19, 2019) ("SSJID Opening Comments").

6 *Id.* at 4.

Replying CCAs likewise encourage the Commission to harness public power options as a means to focus PG&E on the transmission and distribution operations that are at the core of PG&E's safety failures. As the Commission is well aware, a recent Wall Street Journal article highlighted that PG&E had knowledge of the wildfire danger posed by some of its high-voltage power lines for years but failed to properly inspect and maintain its transmission system.[7] Allowing PG&E to maintain a divided focus across a sprawling service area is a continuation of the *status quo* that is not going to produce the changes that California needs. Accordingly, the Replying CCAs encourage the Commission to focus PG&E, or its successor, on the "wires" side of the business so resources can be dedicated to making those facilities safer, while also allowing the sale of these assets to cities and other public entities willing and able to purchase them.

I. RESPONSES TO THE RULING'S AND PARTIES' PROPOSALS

The Replying CCAs appreciate the opportunity to respond to parties' comments regarding the Ruling's specific proposals, as well as the additional proposals that parties have offered.

1. Separating PG&E into Separate Gas and Electric Utilities or Selling Gas Assets.

The Utility Reform Network ("TURN") notes that the question of whether there are ratepayer benefits to separating PG&E's gas and electric operations cannot be properly evaluated at a theoretical level.[8] TURN states: "[t]he net benefits offered by separating PG&E's gas and electric operations, either through restructuring or sale of the gas assets, depends entirely on who would operate PG&E's electric utility and who would operate the gas utility, with what

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7 Katherine Blunt and Russell Gold, *PG&E Knew for Years Its Lines Could Spark Fires, and Didn't Fix Them*, THE WALL STREET JOURNAL (July 10, 2019).

8 I.15-08-019, *Comments of the Utility Reform Network on Proposals to Improve the Safety Culture of Pacific Gas and Electric Company and PG&E Corporation,* p. 3 (July 10, 2019) ("TURN Opening Comments").

motivations, and at what cost."[9] TURN proposes that the Commission should instead "focus on determining the criteria for successor entities or structures, and solicit interest from potential alternatives to PG&E."[10] The Replying CCAs agree.

Given that both PG&E's gas business and electric business continue to have systemic problems that result in safety failures and lead to disastrous and fatal consequences, transformative solutions need to be squarely on the table for serious deliberation. As the Direct Access Customer Coalition observes, a separation of PG&E's gas and electric units would not promote increased safety nearly as well as making PG&E a "wires-only company".[11] The Replying CCAs agree. Wholesale procurement can occupy a significant amount of a load-serving entity's management time and place considerable demands on its financial resources. Removing PG&E from the generation business will allow PG&E to focus its resources as it emerges from bankruptcy on the "wires" part of its electric business, where safety improvements are urgently needed. PG&E's February 13, 2019 comments in this proceeding agreed that "the potential benefit of a wires-only company would be that, by reducing the total number of risks managed by PG&E, it could lead to better management of the remaining risks."[12] Moreover, enabling CCAs to serve the remaining bundled customers within their service areas provides a greater opportunity for CCAs to address local energy priorities and needs.

To effectuate this outcome, the Commission should ensure that communities have the unhindered ability to proactively pursue full community control of retail generation services

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9 *Id.*

10 *Id.* at 6.

11 I.15-08-019, *Comments of the Direct Access Customer Coalition in Response to the Joint Ruling on Proposals to Improve the Safety Culture of Pacific Gas and Electric Company and PG&E Corporation*, p. 2 (July 19, 2019) ("DACC Opening Comments").

12 I.15-08-019, *Opening Comments of Pacific Gas and Electric Company (U 39 M) and PG&E Corporation on Proposals Set Forth in the Joint Assigned Commissioner's and Administrative Law Judge's Ruling Dated June 18, 2019,* p. 34 (July 19, 2019) ("PG&E Opening Comments").

through a variety of local governance models, including full municipalization of the electric system. The Commission should also support legislative amendments to provide local CCA governing boards the ability to be the community energy provider to all customers in the community served by the CCA. Under this framework, when PG&E leaves retail service, PG&E's bundled customers would migrate to an existing, or to be formed, CCA or municipal utility serving their community. Current direct access customers would not be impacted and could retain their service from an energy service provider. This outcome would be an extension of existing trends, in which CCAs, made up of local towns, cities, and counties, currently serve 46% of the retail electric customer load in PG&E's current service area.[13]

2. Establishing Periodic Review of PG&E's CPCN.

The Replying CCAs support periodic review of PG&E's Certificate of Public Convenience and Necessity ("CPCN"). As TURN observes, establishing a periodic review of PG&E's CPCN will help the Commission "acknowledge and prepare for the possibility that alternatives to PG&E will be necessary."[14] Although several parties identify challenges that successor entities may face in successfully taking over PG&E's operations,[15] these concerns can be successfully managed by establishing an appropriate timeframe for CPCN review and by facilitating an early identification of entities that are ready, willing and able to take over PG&E's operations within a defined area. For example, CMUA states "the Commission can ensure that customers would not be stranded by the CPCN revocation by having a mechanism in place in

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13 A. 18-06-001, PG&E 2019 ERRA Forecast. CCAs will serve 32,929 GWh vs. 38,391 GWh of load for bundled customers. Available: https://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=543405

14 TURN Opening Comments at 9.

15 *See*, *e.g.*, I. 15-08-019, *Comments of the Institutional Equity Investors on the Joint Assigned Commissioner's and Administrative Law Judge's Ruling on Proposals to Improve the Safety Culture of Pacific Gas and Electric and PG&E Corporation*, pp. 6-15 (July 19, 2019).

advance of the CPCN review process that ensures qualified entities are willing and able to step into the role of the incumbent utility."[16] Likewise, SSJID takes the position that an immediate review of PG&E's CPCN is warranted and would be more meaningful if the Commission evaluates the other potential entities and options that exist that might better serve California customers.[17] The American Public Power Association ("APPA") states that increased reliance on public power options should be a primary alternative on the table for consideration.[18] The Replying CCAs agree that the Commission should establish a mechanism in advance of the CPCN review process to ensure qualified entities are willing and able to step into the role of the incumbent utility. Doing so will help facilitate a smooth transition to successor entities, as the above parties note. CCAs are ideally situated to take over PG&E's retail services should CPCN review identify doing so as a means to increase safety because CCAs already serve approximately 85%-95% of the retail load in their service territories.[19] Thus, PG&E's exit from retail service would have a relatively limited impact on service within a CCA service area.

With respect to the timeframe for CPCN review, TURN proposes that PG&E's CPCN should be subject to immediate review, and if the Commission renews PG&E's CPCN, subsequent reviews should occur no more frequently than every 20 – 30 years.[20] The Replying CCAs believe this is a reasonable timeframe, as this duration addresses concerns that CPCN review could lead to disincentives to invest. This timeframe is consistent with timeframes

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[16] CMUA Opening Comments at 4.

[17] SSJID Opening Comments at 4.

[18] I.15-08-019, *Opening Comments of the American Public Power Association to Joint Assigned Commissioner's and Administrative Law Judge's June 18, 2019 Ruling*, at p. 4 (July 19, 2019).

[19] In PCE's case, only a little over 2% of customers opted to stay with PG&E during PCE's formation. For SJCE, a little over 1% of customers have opted to stay with PG&E.

[20] TURN Opening Comments at 11.

localities utilize when reviewing other franchise agreements. These sorts of periodic reviews have not resulted in disincentives to invest in facilities that are subject to review.

The Replying CCAs also agree with CMUA that in the event the Commission finds that PG&E's CPCN should be revoked, the Commission should take additional action to ensure that PG&E does not erect barriers to organizations that would propose to replace part, or all, of PG&E's service territory as a result of the CPCN revocation.[21]

3. Modification or Elimination of PG&E Corp.'s Holding Company Structure.

The Replying CCAs do not take a position on this proposal at this time.

4. Linking PG&E's Return on Equity to Safety Performance Metrics.

The Replying CCAs agree with parties that support linking PG&E's return on equity to safety performance metrics.[22] The Replying CCAs also agree with commenters that any linkage of rate of return or return on equity to safety must be in the form of a potential reduction in authorized returns, not a potential adder.[23] Providing safe and reliable service is a foundational requirement of holding a CPCN and a duty owed by the monopoly franchisee. Accordingly, there should be no reward to PG&E for meeting foundational safety requirements. Instead, when a utility fails to meet safety requirements there should be a reduction in authorized rate of return or return on equity. The potential for a reduction in authorized rate of return sends a clear signal

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[21] CMUA Opening Comments at 4-5.

[22] I.15-08-019, *Comments of the Center for Climate Protection in response to the Joint Assigned Commissioner's and Administrative Law Judge's Ruling on Proposals to Improve the Safety Culture of Pacific Gas and Electric Company and PG&E Corporation dated June 18, 2019*, pp. 6-9 (July 19, 2019); DACC Opening Comments at 10-11; *Comments of Engineers and Scientists of California on Proposals to Improve Safety Culture,* pp. 5-7 (July 19, 2019); *Mussey Grade Road Alliance Comments on Joint Assigned Commissioner's and Administrative Law Judge's Ruling on Proposals*, pp. 3-6 (July 19, 2019); PG&E Opening Comments at 22-24 (stating it "does not object to considering conditioning a portion of its ROE on safety performance"); *Opening Comments of William B. Abrams on Proposals to Improve the Safety Culture of Pacific Gas and Electric Company and PG&E Corporation*, pp. 8-16 (July 19, 2019).

[23] *See*, *e.g.*, TURN Opening Comments at 16.

to investors that they too must ensure the utilities they invest in are maintaining safety at required levels.

However, Replying CCAs agree with TURN's recommendation that the Commission should postpone action on this proposal until the related provisions of AB 1054 have been implemented in order to avoid the potential for adopting conflicting requirements regarding executive incentive compensation and safety.[24] TURN also recommends that the Commission coordinate the consideration of metrics across all proceedings and attempt to create a unified, cohesive set of safety metrics that address not just wildfire safety but safety culture more generally.[25] The Replying CCAs agree with these recommendations, as they will help the Commission avoid adopting performance metrics in different proceedings that may send conflicting messages to PG&E.

5. Other Proposals.

TURN renews its suggestion that the Commission should invite preliminary expressions of interest to provide the Commission with more insight into potential alternatives to PG&E's continued provision of electric and gas services.[26] Specifically, TURN recommends that the Commission take two steps "posthaste".[27] First, the Commission should "adopt a process for requesting expressions of interest by non-PG&E entities in serving PG&E's customers."[28] Second, the Commission should "collect information necessary to evaluate whether any

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24 TURN Opening Comments at 19-20.
25 *Id*, at 20-21.
26 *Id.* at 23-25.
27 *Id.* at 24.
28 *Id.*

customers would be harmed by breaking up PG&E's service territory."[29] The Replying CCAs support these proposals.

Parties' comments in this proceeding continue to highlight that California's investor-owned utilities are increasingly consumed with the serious and troubling consequences resulting from wildfires, safety breaches, and challenges to financial solvency. For some time now, local communities have initiated bold and ambitious actions to reduce carbon emissions in transportation, buildings, existing public utilities they manage (*e.g.*, water, wastewater), and the electric sector through CCAs and publicly owned utilities. The Replying CCAs believe a number of existing CCAs may be interested in taking additional responsibility for supplying electricity and related services to their residents and would welcome the opportunity to respond to a request for preliminary expressions of interest, such as TURN proposes.

II. CONCLUSION

The Replying CCAs appreciate the opportunity to respond to parties' opening comments and look forward to working with the Commission and parties in this proceeding to identify the best path forward for providing Northern California with safe and reliable electric and gas service at just and reasonable rates, in light of PG&E's safety failures and recent bankruptcy filing.

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[29] *Id.* at 25.

Respectfully submitted,

/s/ Joseph Wiedman

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For the Peninsula Clean Energy Authority, Marin Clean Energy, San Jose Clean Energy, Pioneer Community Energy, and Silicon Valley Clean Energy

Dated: August 2, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) for Authority to Establish Its Authorized Cost of Capital for Utility Operations for 2020 and to Partially Reset the Annual Cost of Capital Adjustment Mechanism.	Application 19-04-014 (Filed April 22, 2019)
And Related Matters.	Application 19-04-015 Application 19-04-017 Application 19-04-018

JOINT CCA
3-DAY ADVANCE NOTICE OF EX PARTE COMMUNICATION

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September 25, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) for Authority to Establish Its Authorized Cost of Capital for Utility Operations for 2020 and to Partially Reset the Annual Cost of Capital Adjustment Mechanism.	Application 19-04-014 (Filed April 22, 2019)
And Related Matters.	Application 19-04-015 Application 19-04-017 Application 19-04-018

JOINT CCA
3-DAY ADVANCE NOTICE OF EX PARTE COMMUNICATION

Pursuant to Public Utilities Code Section 1701.1(e)(3) and Rules 8.3 and 8.4 of the California Public Utilities Commission's Rules of Practice and Procedure, Marin Clean Energy ("MCE"), East Bay Community Energy ("EBCE"), and Sonoma Clean Power ("SCP"), collectively the Joint CCAs, hereby provide advance notice of their scheduled *ex parte* communication with James Ralph, Chief of Staff to President Batjer. The Joint CCAs' scheduled *ex parte* communication will be conducted orally, with no written materials provided. The meeting will occur in-person, at approximately 3:00 PM at the offices of the California Public Utilities Commission, located at 505 Van Ness Avenue, San Francisco, California on September 30, 2019. MCE initiated this communication. The following individuals will participate in the *ex parte* communication for the Joint CCAs: Michael Callahan, MCE Senior Policy Counsel; Todd Edminster, EBCE Director of Regulatory Affairs and Deputy General Counsel; and Neal Reardon, SCP Director of Regulatory Affairs.

Respectfully submitted,

/s/ Daniel Settlemyer

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September 25, 2019

September 30, 2019

CA Public Utilities Commission
Energy Division
Attention: Tariff Unit
505 Van Ness Avenue, 4th Floor
San Francisco, CA 94102-3298

Reply to Protest of MCE Advice Letter 37-E

Re: The Public Advocates Office's Protest of Marin Clean Energy's Advice Letter 37-E (Energy Efficiency Annual Budget Advice Letter for Program Year 2020)

Dear Energy Division Tariff Unit:

Marin Clean Energy ("MCE") hereby replies to a protest dated September 23, 2019 from the Public Advocates Office ("PAO") to MCE's Advice Letter 37-E Marin Clean Energy's 2020 Energy Efficiency Annual Budget Advice Letter ("2020 ABAL"), filed September 3, 2019.

I. Statewide issues

PAO protests the 2020 ABAL of all energy efficiency ("EE") program administrators ("PAs") claiming that the Commission must ensure that the statewide EE portfolio is cost-effective[1] and requesting that the Commission adopt remedies to improve the cost effectiveness of all PA's EE portfolios.[2]

MCE disagrees with this premise for several reasons. First and foremost, there is no legal basis for this argument; indeed, it contradicts several previous Commission Decisions which clearly established that <u>each PA's</u> EE portfolio must be cost-effective at the portfolio level.[3] PAO is *de facto* recommending a statewide cost-effectiveness requirement contrary to existing Commission direction and precedent.
Second, the Annual Budget Advice Letter is not the appropriate venue to propose and implement any policy changes. These issues were appropriately litigated through Rulemaking 13-11-005.
Third, PAO's proposal inequitably affects PAs that have met the Commission's Total Resource Cost ("TRC") requirements. It is not appropriate to subject PAs that meet the required TRC ratio

[1] PAO's protest of MCE's Advice Letter 37-E ("PAO protest") at 3

[2] *Ibid* at 11 and 46-49

[3] As PAO points out in its protest, both D.12-11-015 (at 100) and D.18-05-041 (OP 13 at 185) establish that each utility's EE portfolio must be cost-effective. D.14-01-033 established a cost-effectiveness standard for CCA program portfolios (OP 3 at 50).

to the same proposed improvements as PAs that do not meet the required TRC ratio (i.e., PG&E and SCE).
Fourth, the Commission intentionally did not set cost-effectiveness thresholds for Regional Energy Networks ("RENs") due to REN programs serving gaps in Investor-Owned-Utility ("IOU") programs and hard to reach markets. D.12-11-015 established:

> "It should also be noted that many of the REN program plans address hard to reach market segments that are generally more expensive than average to deliver. REN proposals should not be punished for that, because, if successful, their pilot approaches could lead to breakthroughs for more cost-effective solutions in the future… Therefore, the Commission will not set a threshold cost-effectiveness level, either TRC or PAC, for RENs at this time."[4]

PAO's proposal to retroactively apply cost-effectiveness standards for all PAs in spite of this intentional decision in order to encourage market growth for hard-to-reach customers is inconsistent.

Therefore, MCE requests that the Commission reject PAO's request to require each PA to improve its portfolio net benefits in proportion to its share of the statewide budget to achieve a statewide cost-effective EE portfolio.

II. MCE's residential meter-based savings program

In the following section, MCE addresses PAO's concerns regarding MCE's Single-Family Comprehensive program ("SF Comprehensive Program").

As an initial matter, MCE would like to offer additional information on the design of the SF Comprehensive Program and clarify how any potential overlap or double-dipping concerns with PG&E programs have been and will continue to be addressed.
MCE's SF Comprehensive Program is a new, third-party implemented program under MCE's EE portfolio that is currently in the final stages of contract negotiations. The program is expected to offer home energy reports and energy savings recommendations to single-family residential customers, leveraging Normalized Metered Energy Consumption ("NMEC") and hourly load profiles. Savings will be quantified using CalTRACK methods and a Randomized Controlled Trial ("RCT"). In addition, the program offers opt-in participation through a web-based platform which provides an opportunity to set energy "budgets" and customized alerts, and provides access to an online equipment/appliance marketplace.
With regard to coordination with PG&E's Home Energy Reports ("HERs") program, MCE would like to point out that coordination on potentially duplicative programs between MCE's and PG&E's EE portfolios is formalized through the Joint Cooperation Memorandum ("JCM") that is mandated per D.18-05-041[5] and is filed annually with the Commission in June. The JCM provides

[4] D.12-11-005, Decision Approving 2013-2014 Energy Efficiency Programs and Budgets, at 19

[5] D.18-05-041, Decision Addressing Energy Efficiency Business Plans, at 111 and 122.

a framework for addressing double-dipping and identifying areas of overlap, and MCE and PG&E are already in conversation surrounding the residential EE portfolio, including the SF Comprehensive Program.

Secondly, MCE disagrees with PAO's claim that MCE's forecast for its residential meter-based savings program is unsubstantiated while contributing disproportionally to the cost effectiveness of MCE's overall EE portfolio.[6] PAO claims that "MCE's portfolio **relies heavily** (emphasis added) on its unsupported forecasts for a single cost-effective residential program, the residential Single-Family Comprehensive program (MCE07)."[7] MCE respectfully disagrees with this statement and clarifies that MCE's net benefits for this program account for <u>12 percent</u> of MCE total portfolio net benefits. MCE's portfolio consists of nine distinct program offerings (not including EM&V). MCE opines that this is an appropriate ratio of net benefits for the residential Single-Family Comprehensive program ("SF Comprehensive Program") within the overall program portfolio.

MCE would also like to point out that MCE's portfolio TRC excluding the SF Comprehensive Program while leaving all other data the same, would result in a portfolio TRC of 0.96, a mere 5 percent decrease from MCE's portfolio TRC forecast of 1.01.

Although the SF Comprehensive Program accounts for 35.6 percent of MCE's total electricity savings, MCE is confident in the energy savings forecast for this program for the following reasons:

1. The program is designed to treat the highest consumption quartile of customers and all savings assumptions have been made utilizing the average annual energy consumption of that cohort.
2. MCE's implementation partner developed savings forecasts consistent with verified results in California and other comparable climate and housing stock markets.
3. Program savings are forecasted to slowly ramp up to steady-state savings of 1.5% of annual consumption by year 3 of the program.
4. PG&E's HERs program has delivered similar results and there is no evidence to assume that MCE's program would be any different.
5. MCE's program will be measured according to Normalized Metered Energy Consumption ("NMEC") measurement guidelines using CalTRACK. MCE's implementation partner has performed validation tests to ensure that CalTRACK measured results materialize in a manner consistent with the more familiar Randomized Control Trial ("RCT") experimental design typically utilized for behavioral programs.
6. MCE and its implementation partner have built the payment schedule of this program on a pay-for-performance ("P4P") basis. There are no fixed third-party costs to MCE to deliver this program, rather the implementation partner will be paid based on annual realized energy savings.

[6] PAO protest at 36

[7] *Ibid*

Thirdly, MCE would like to offer some clarifications regarding PAO's concerns that past results for this program do not support MCE's forecast in the 2020 ABAL.[8]
The SF Comprehensive Program is a new program that MCE expected to develop and launch in 2019. In its 2019 ABAL, MCE forecasted a more conservative TRC and savings for the 2019 program year as the program design had yet to be defined and a program ramp up period was included in the forecast. While the program has not launched to date yet due to extended timelines in bringing a new program design into MCE's portfolio, MCE is now in the final stages of contracting for the program and hence had substantially more information about the program design when filing its 2020 ABAL. The updated TRC ratio and savings included in the 2020 ABAL are accurate forecasts of the expected cost effectiveness and energy savings under the SF Comprehensive Program in 2020 based on the updated program design developed by the implementer to date.

For the reasons stated above, MCE respectfully request the Commission reject PAO's request to require MCE file a supplemental ABAL on this matter.

III. Rebates that exceed measure costs

MCE would like to offer a few arguments to rebut PAO's claim that MCE provides excessively high rebates in MCE's industrial, agricultural, and commercial programs.[9]

Firstly, the measures identified by PAO are Strategic Energy Management ("SEM") measures, where it is plausible to have an incentive cost that exceeds the measure cost due to the structure of incentive payments and behavioral and retro-commissioning measures. The focus of SEM is on low-cost or no-cost measures that are influenced by the coaching and continuous feedback on performance that these platforms provide, and incentives come in the form of milestone payments as well as performance-based rates.

Secondly, MCE would like to highlight some nuance in regards to requirements for incentive and measure costs based on previous Commission guidance. As PAO states, Commission policy generally does not allow PAs to offer rebates that exceed the incremental cost of a measure.[10] However, PAO stops short in explaining that D.06-06-063 provides for exceptions where the incentive can exceed the measure costs. D.06-06-063 states

> "We recognize that there may be limited instances for program design purposes where the cash rebate to the customer exceeds the measure installation cost… It was precisely to address these types of circumstances that we adopted the "Dual Test" of cost-effectiveness in our policy rules. Those rules recognize that both the TRC and PAC tests of cost effectiveness need to be considered when evaluating program proposals, in order to ensure

[8] PAO protest at 28

[9] *Ibid* at 39

[10] *Ibid* at 39, based on D.06-06-063, p.72 and CPUC EE Policy Manual (version 5), pp. 18-19

> that program administrators and implementers do not spend more on rebates/cash incentives than absolutely necessary to achieve TRC net benefits."[11]

Incentives that aren't included in the TRC are included and negatively impacts the PAC. MCE is not providing excessively high rebates under our agricultural, industrial and commercial programs as its portfolio as a whole pass both the TRC and PAC tests. Therefore, MCE respectfully requests the Commission reject PAO's request for MCE to file a supplemental ABAL on this matter.

IV. Conclusion

For the reasons stated above, MCE respectfully requests the Commission reject PAO's protest of MCE AL 37-E, Marin Clean Energy's 2020 Energy Efficiency Annual Budget Advice Letter.

Respectfully submitted,

/s/ *Jana Kopyciok-Lande*_
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Service List R.13-11-005

[11] D.06-06-063 at 72

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for the California Solar Initiative, the Self-Generation Incentive Program and Other Distributed Generation Issues	)))))	Rulemaking 12-11-005 (Filed November 17, 2017)

OPENING COMMENTS OF THE JOINT CCA PARTIES ON THE PROPOSED DECISION

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August 29, 2019

For: Marin Clean Energy
Sonoma Clean Power Authority
Peninsula Clean Energy

TABLE OF AUTHORITIES

SUBJECT INDEX OF RECOMMENDED CHANGES

The Joint CCAs recommend the following changes to the Proposed Decision:

1. The definition of eligible critical resiliency needs residential customers should be based on the likelihood that the customers will experience PSPS outages, not their location in High Fire Threat Districts. The requirement that residential customers be located in Tier 3 HFTDs should be changed to a requirement that the customer either: a) is located served by a circuit identified by the distribution IOU as among the top 20% of circuits likely to be de-energized; or b) is located in an area identified by the IOU as likely to experience de-energization.

2. If a distribution does not have the information needed to categorize customers based on likelihood of de-energization, it should be allowed to use HFTD categorization as a temporary proxy for a period no greater than two years.

3. The definition of critical facilities should be expanded to include: public facility maintenance/corporate yards; emergency call and dispatch centers; critical transport facilities (including bridges, tunnels, railroad and air traffic control infrastructure); and critical communications infrastructure.

4. The PD should adopt an explicit requirement that CCA customers be guaranteed fair and equal access to ERP funds.

5. The PD should expand immediate ERP funding from $100 million to $400 million.

6. Initial funding priority should be given to resiliency resources for customers with life-support designations and first-responder, medical, water, and sanitation facilities.

7. Distribution utilities should be required to identify life support customers within their service territories and share this information with the PAs. The PAs should be required to reach out to high PSPS risk life-support customers and provide them with fully subsidized resiliency resources whenever possible.

8. In this docket the Commission should explore opportunities to unlock the RA value of resources subsidized by this program.

9. The Commission should require the IOUs and PAs to coordinate the CCAs in development of their ERP marketing, education, and outreach ("ME&O") programs and allow CCAs to qualify for MEO funding depending on the MEO programs that emerge.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for the California Solar Initiative, the Self-Generation Incentive Program and Other Distributed Generation Issues	)))))	Rulemaking 12-11-005 (Filed November 17, 2017)

OPENING COMMENTS OF THE JOINT CCA PARTIES ON THE PROPOSED DECISION

In accordance with Rule 14.3 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission"), Marin Clean Energy ("MCE"), Sonoma Clean Power Authority ("SCP"), and Peninsula Clean Energy ("PCE") (together, the "Joint CCA Parties" or "Joint CCAs") hereby submit the following opening comments on the August 9, 2019 *Proposed Decision of Commissioner Rechtschaffeen* ("PD") in the above-captioned proceeding, Rulemaking ("R.") 12-11-005. As set forth below, the Joint CCAs strongly support the Equity Resiliency Program ("ERP") created by the PD, but believe that the program could be significantly strengthened by adopting changes to the ERP's eligibility criteria, program budget, and program administration. These changes are discussed below and are reflected in the proposed modifications to the PD's Findings, Conclusions, and Ordering Paragraphs set forth in Appendix A to these comments.

I. COMMENTS ON THE PROPOSED DECISION

A. The Joint CCAs Strongly Support The Creation Of An Equity Resiliency Program

The Joint CCAs strongly support the PD's creation of an Equity Resiliency Program ("ERP") that will provide funding for energy resiliency resources to mitigate some of the impact of likely future Public Safety Power Shutoff ("PSPS") events on some of the State's most vulnerable residents. It is beyond dispute that the frequency, scope, and duration of PSPS events in the Investor Owned Utilities' ("IOU") distribution service territories is likely to drastically increase going forward.

The Joint CCAs recognize the importance of preventing catastrophic utility-caused wildfires. MCE and SCP serve communities that were directly impacted by the devastating October 2017 wildfires in Napa and Sonoma counties. The Joint CCAs support the use of *reasonable* and *targeted* PSPS shutoffs as an *interim measure* to prevent wildfires until more permanent and sustainable wildfire prevention solutions can be implemented.

At the same time, it is essential that the Commission recognize that a large-scale multi-day PSPS event, in itself, can have negative impacts equivalent to those of a significant natural disaster. Without electricity, most economic activity within a community will stop. Cell phones and internet connections are unlikely to work, as are ATMs and credit/debit cards. Water and wastewater systems that rely on electric pumps may not be able to operate properly, causing areas to lose water service entirely or leading to contamination that makes tap water undrinkable. Interrupted wastewater service could lead to significant sanitation and public health problems. During high-heat events, the lack of electricity to run fans and air conditioners can be dangerous for the elderly, the very young, and individuals with serious illness, a problem that would be greatly exacerbated if the water supply is compromised.

The Commission has the advantage of knowing that PSPS events are coming, and of knowing how to mitigate the worst impacts on the most vulnerable customer groups: customers that rely on life-support or essential medical equipment can be protected through the installation of combined solar/battery systems that can meet their basic electricity needs in the event of a multi-day power shutoff, and facilities that provide vulnerable customers with essential services can be provided with similar solar/battery systems. The ERP is an important first step towards providing these essential protections.

B. Comments on ERP Program Eligibility

i. *Program Eligibility Should Be Based On The Likelihood Of PSPS Outage, Not High Fire Threat District Categorization.*

The PD currently defines ERP program eligibility based on the fire threat designations adopted by the Commission's Safety Enforcement Division pursuant to D.17-01-009. Under the PD, ERP eligibility for residential customers is limited to "SGIP critical resiliency needs" residential customers ("CRN Customers"). The PD defines CRN customers as customers that are located in the highest fire threat areas, known as "Tier 3 High Fire Threat Districts" ("HFTDs"), and are: 1) eligible for the equity budget; 2) enrolled in the medical baseline program; or 3) have notified their utility of serious illness or condition that could become life threatening if electricity is disconnected.[1]

Under the PD, critical facilities are eligible for ERP funds if they are: 1) located in Tier 2 or Tier 3 HFTDs; and 2) provide critical services or infrastructure to a community that is located in a Tier 3 HFTD and is eligible for the equity budget.[2]

The purpose of the ERP is to mitigate the harms caused by PSPS events.[3] A customer's qualification for ERP funding should be based on the likelihood that the customer will be exposed to PSPS shutoffs and the likely duration/severity of those shutoffs. An area's HFTD categorization is only a rough proxy for the likelihood that the area will be impacted by PSPS shutoffs, as the HFTD maps do not account for the structure of IOUs' distribution and transmission networks. As PG&E states on its PSPS website:

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1 PD at 23.
2 PD at 24–25.
3 PD at 22.

> While customers in high fire-threat areas (based on the CPUC High Fire-Threat Map) are more likely to be affected, a public safety power outage could impact any of the more than 5 million customers who receive electric service from PG&E. This is because the energy system relies on power lines working together to provide electricity across cities, counties and regions.[4]

Thus, a customer may be located in a relatively low fire-risk area and still have an extremely high likelihood of PSPS shutoff if that customer is served by a high fire risk circuit.

In order to ensure that the definition of CRN Customers includes those customers that are most likely to be impacted by PSPS shutoffs, the PD should be modified to replace the requirement that CRN Customers be located within Tier 3 fire zones with the requirement that CRN Customers meet one of the following two PSPS risk criteria:

- The customer is located served by a circuit identified by the distribution IOU as among the top 20% of circuits likely to be de-energized;
- Or, the customer is located in an area identified by the IOU as likely to experience de-energization.

PG&E, for instance, has developed a granular map of areas likely to experience PSPS deenergization that could inform these criteria.[5] In the event that a distribution IOU does not have granular circuit and locational PSPS risk information, the PD should allow the IOU to provide the PAs with HFTD maps as a proxy until the IOU has developed the appropriate PSPS risk estimates. The PD should allow distribution IOUs to use HFTD maps as a proxy for no more than two years.

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[4] Available at: https://www.pge.com/en_US/safety/emergency-preparedness/natural-disaster/wildfires/public-safety-power-shutoff-faq.page

[5] Available at: https://www.pge.com/en_US/safety/emergency-preparedness/natural-disaster/wildfires/psps-event-maps.page

ii. *The Program's Definition of Critical Facilities Should Be Expanded*

For the purposes of ERP funding eligibility, the PD limits the definition of "Critical Facilities" to the following:[6]

- Police stations
- Fire stations
- Emergency response providers as defined in D.19-05-042
- Emergency operations centers
- Medical facilities (hospitals, nursing homes, blood banks, health care facilities, dialysis centers, hospice facilities)
- Public and private gas, electric, water, wastewater, or flood control facilities
- Jails and prisons
- Locations designated by IOUs to provide customers with assistance during PSPS events
- Government-designated cooling centers
- Government-supported homeless shelters

The Joint CCAs agree with the categories included in this definition, but, based upon discussions with our local first responder stakeholders, believe that the PD should be amended to include the following as eligible "Critical Facilities:"

- Public facility maintenance/corporate yards
- Emergency call and dispatch centers
- Critical transport facilities (including bridges, tunnels, railroad control infrastructure)
- Critical communications infrastructure

These facilities provide essential public services and are properly viewed as "the most critical facilities and infrastructure."[7] For instance, public facility maintenance/corporate yards are essential for providing public services and emergency repairs and maintenance to critical public infrastructure. Emergency call and dispatch centers and critical communications infrastructure

[6] PD at 26.
[7] PD at 25.

are essential for coordinating emergency response efforts during PSPS events. And critical transportation facilities such as moving bridges, tunnels, railroad control infrastructure, and air traffic control are essential for public safety.

iii. *The PD Should Require That Customers In CCA Territories Have Fair Access to ERP Funds*

Both CCA customers and the IOU bundled customers pay for the SGIP program. Basic fairness and the prohibition against cost-shifting between customer groups require that qualifying customers and critical facilities served by CCA programs have fair and equal access to ERP Funds, even if the PA administering the ERP is an IOU. The PD should be amended to include an explicit requirement that ERP funds be allocated in a non-discriminatory manner.

C. Comments on ERP Program Budget

i. *The Commission Should Significantly Expand Equity Resiliency Program Funding To Protect Highly Vulnerable Customers From PSPS Impacts*

The PD should be modified to dedicate the entirety of the $400 million SGIP budget surplus to the ERP. Large-scale multi-day PSPS events are disaster-level events that can be life threatening and economically devastating. In this "new normal," preventing loss of life due to PSPS events must be the Commission's top priority. The PD's allocation of $100 million towards the ERP demonstrates Commission's recognition of the serious issues it faces, and the need for immediate action.

However, California is a large state with many vulnerable residents in that live in high PSPS risk zones or are served by high PSPS risk circuits. To mitigate the impact of multi-day PSPS events, most vulnerable customers will require a basic combined solar/storage system that provides enough power to operate essential medical equipment, meet basic cooling needs, and meet basic household electrical needs over a multi-day period. In addition, it is essential that the Commission provide adequate incentives to ensure that facilities that provide essential services to vulnerable customers, including, most critically, first responders, medical facilities, and water and sanitation infrastructure, have adequate electricity to continue operation during multi-day PSPS events.

$100 million is not enough to provide these vulnerable high PSPS risk residents – and the essential public service facilities that they rely upon – with adequate resiliency resources. While the potential impacts of widespread PSPS events are an unprecedented problem, the Commission has an unprecedented opportunity to mitigate these impacts – the SGIP budget currently has an unspent surplus of over $400 million. The entirety of this surplus should be immediately be allocated towards resiliency resources to protect the most high-risk customers from PSPS-related harms.

In addition, the Joint CCAs' strongly support the PD's conclusion that, in a future Decision in this rulemaking, the Commission should consider allocating $100 million a year to the ERP budget going forward. Given the urgent need for resiliency resources, consideration of this proposal should be fast-tracked, and budget allocations greater than $100 million a year should be considered.

ii. *Initial Funding Priority Should Be Given to Life Support Customers and Life-Sustaining Infrastructure*

The PD should be modified to require that the SGIP Program Administrators ("PAs") initially prioritize providing resiliency resources to customers with a life-support ("LS") designation and first-responder, medical, water, and sanitation facilities. LS customers rely on electrically powered medical equipment for survival, and any interruption in power to these customers could be a life threatening event. Similarly, first-responders, medical facilities, and water and sanitation facilities are essential for preserving the public health and safety, and should receive first priority.

Given the urgency of the need to protect the most vulnerable customers and ensure that life-sustaining public services continue during PSPS events, normal outreach efforts are not likely to be adequate. The PD should be modified to require that the distribution utilities identify all life-support customers located within their service territories, and to share this list with the appropriate PAs. The PAs should then be required to proactively reach out to life-support customers in high PSPS risk areas and served by high PSPS risk circuits, and should take steps to provide them with fully-subsidized solar/storage systems wherever possible. The PAs should also be required to proactively contact local agencies that provide life-sustaining public services to high PSPS risk residents and work with them to identify resiliency resource needs and provide subsidized resiliency resources to meet those needs.

D. Comments on ERP Program Administration

i. *The Commission Should Explore The RA Value Of ERP Resources*

The Commission should move expeditiously in a subsequent phase of this docket to explore opportunities to unlock resource adequacy value of the facilities that are being incentivized by this new program. The Commission should also move expeditiously to consider other opportunities to unlock the value of the facilities being deployed via demand response and other services. For the majority of the time, the facilities being deployed under the new program will not be utilized for PSPS events. Accordingly, efforts should be undertaken to ensure the facilities can be aggregated or utilized in ways that provide greater value to all energy consumers helping support these deployments.

ii. *CCA Programs Should Be Included In ERP Marketing And Outreach Efforts And Qualify For ERP Marketing and Outreach Funds*

CCAs are ideal partners in the state's resiliency efforts. CCAs are "closer to the ground" due to their relationships with local agencies and ties to the community, so we are trusted partners in our communities. We can also leverage these existing avenues to reach vulnerable and marginalized communities. The CCAs participating in this docket have already begun outreach and coordination efforts with our local first responders and representatives of vulnerable communities to assess their needs as this conversation has been taking place at the Commission. Our goal is to develop programs and policies that can support community resiliency including by facilitating participation in this program. To support our efforts, we request that the Commission require the IOUs and PAs to coordinate the CCAs in development of their ERP marketing, education, and outreach ("ME&O") programs and allow CCAs to qualify for MEO funding depending on the MEO programs that emerge.

E. Comments On Heat Pump Water Heaters

The Joint CCAs support the PD's adoption of an initial budget of $4 million for heat pump water heaters ("HPWHs"). Due to their high potential for greenhouse gas reduction (both locally for the customer and as a grid resource), several CCAs are already implementing or in the process of designing heat pump water heater programs. The expansion of SGIP to cover heat pump water heaters will allow for additional funds that will help speed market transformation of the water heater sector. The Joint CCAs look forward to working with the Commission to develop a more robust HPWH program going forward.

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IV. CONCLUSION

The Joint CCAs thank the Commission for its consideration of these comments. For the reasons discussed herein, the Joint CCAs respectfully ask that the Commission adopt the modifications and additions to the PD's Findings of Fact, Conclusions of Law, and Ordering Paragraphs set forth in Appendix A.

Dated: August 29, 2019

Respectfully submitted,

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APPENDIX A: APPENDIX OF PROPOSED MODIFICATIONS
(Modifications to existing language: deletions are shown as strike-outs; additions are underlined and italicized)

MODIFICATIONS TO CONCLUSIONS OF LAW:

Modify Conclusion of Law 5 as Follows:

5. For SGIP purposes, the Commission should define residential customers with critical resiliency needs as customers that are: (a) are *either: (i) served by a circuit identified by the distribution IOU as among the top 20% of circuits likely to be deenergized; or (ii) is located in an area identified by the IOU as likely to experience deenergization* ~~located within a Tier 3 HFTD;~~ and, (b) are one of the following: (i) eligible for the equity budget; (ii) a medical baseline customer; or (iii) a customer that has notified their utility of serious illness or condition that could become life-threatening if electricity is disconnected. *If an IOU does not have sufficient information to determine whether a customer is likely to be subject to PSPS deenergization, it may rely on customer location within Tier 3 fire zones as a temporary proxy for a period of no greater than two years.*

Modify Conclusion of Law 6 as Follows:

6. For SGIP purposes, the Commission should define non-residential customers as having critical resiliency needs if they ~~are located in a Tier 2 or Tier 3 HFTD~~ and provide critical facilities or infrastructure as defined in this decision for a community that is *identified as likely to experience PSPS deenergization* ~~located in a Tier 3 HFTD~~ and *is* eligible for the equity budget.

Modify Conclusion of Law 7 as Follows:

7. For SGIP purposes, eligible non-residential critical resiliency needs customers should be police stations; fire stations; emergency response providers as defined in D.19-05-042; emergency operations centers; medical facilities including hospitals, skilled nursing facilities, nursing homes, blood banks, health care facilities, dialysis centers and hospice facilities; public and private gas, electric, water, wastewater or flood control facilities; jails and prisons; locations designated by the IOUs to provide assistance during PSPS events; cooling centers designated by state or local governments; *public facility maintenance/corporate yards; emergency call and dispatch centers; critical transport facilities (including bridges, tunnels, railroad and air traffic control infrastructure); critical communications infrastructure;* and, homeless shelters supported by federal, state, or local governments.

Modify Conclusion of Law 24 as Follows:

24. The Commission should direct the PAs to develop a customized equity budget ME&O Plan that: (a) co-promotes SGIP equity budget incentives alongside SASH, DAC-SASH and SOMAH incentives; (b) prioritizes outreach methods to rapidly inform

customers with critical resiliency needs about the availability of SGIP incentives and how they can identify and apply for battery storage systems that are appropriate for resiliency*;* *and (c) encourages CCA participation in ME&O outreach and provides CCAs with funding for ME&O efforts within their service territories*.

Modify Conclusion of Law 30 as Follows:

30. The Commission should establish a new ~~$100~~ *$400* million budget set-aside for equity budget customers with critical resiliency needs and HFTD SASH/DAC-SASH customers by directing the SGIP PAs to transfer ~~$100~~ *$400* million from the accumulated unused generation technology budget to a new equity resiliency budget.

Modify Conclusion of Law 31 as Follows:

31. The Commission should direct the SGIP PAs to transfer the following amounts of funds from each PA's accumulated unused generation technology budget to the new equity resiliency budget:

Program Administrator	Budget (in millions)
PG&E	~~$44~~ *$176*
SCE	~~$33~~ *$132*
CSE	~~$13~~ *$52*
SoCalGas	~~$9~~ *$36*
Total	~~$100~~ *$400*

New Conclusion of Law:

CCA customers should be given fair and equal access to ERP funds.

New Conclusion of Law:

Initial ERP funding priority should be given to resiliency resources for customers with life-support designations and first-responder, medical, water, and sanitation facilities.

New Conclusion of Law:

Distribution utilities should be required to identify life support customers within their service territories and share this information with the PAs. The PAs should be required to reach out to high PSPS risk life-support customers and provide them with fully subsidized resiliency resources whenever possible.

<u>MODIFICATIONS TO ORDERING PARAGRAPHS:</u>

Modify Ordering Paragraph 3 as Follows:

3. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), Southern California Gas Company (SoCalGas) and the Center for Sustainable Energy (CSE) are directed to allocate accumulated unused incentive funds to the following budget categories:

Program Administrator	Equity Resiliency Budget (in millions)	Equity Heat Pump Water Heater Budget (in millions)
PG&E	~~$44~~ *<u>$176</u>*	$1.76
SCE	~~$33~~ *<u>$132</u>*	$1.36
CSE	~~$13~~ *<u>$52</u>*	$0.52
SoCalGas	~~$9~~ *<u>$36</u>*	$0.36
Total	~~$100~~ *<u>$400</u>*	$4

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)

COMMENTS OF MARIN CLEAN ENERGY AND THE ASSOCIATION OF BAY AREA GOVERNMENTS ON BEHALF OF THE SAN FRANCISCO BAY AREA REGIONAL ENERGY NETWORK ON DRAFT REVISED RULEBOOK FOR NORMALIZED METERED ENERGY CONSUMPTION

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September 30, 2019

I. INTRODUCTION

In accordance with the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission"), Marin Clean Energy ("MCE") and the Association of Bay Area Governments ("ABAG"), on behalf of the San Francisco Bay Area Regional Energy Network ("BayREN"), submit the following comments in response to the *Administrative Law Judges' Ruling Issuing Draft Revised Rulebook for Normalized Metered Energy Consumption and Inviting Comments on Population-Level Rules, Measurement Methods and Calculation Software* filed August 29, 2019 ("August 29 Ruling"). The August 29 Ruling provides notice that the staff of the Energy Division of the Commission have prepared a draft revised rulebook for normalized metered energy consumption ("NMEC"). The ruling introduces new rules for population-level NMEC programs, as well as language pertaining to NMEC measurement methods and calculation software, which are intended to apply to both population- and site-level NMEC programs, and poses six specific questions.

MCE and BayREN applaud the Commission for taking the initiative to develop appropriate and effective rules for both site-level and population-level NMEC programs and projects. Both MCE and BayREN see NMEC as a way to improve the accuracy of savings claims under the energy efficiency ("EE") programs portfolio, deliver maximum customer value, reduce administrative burden, drive innovation, and improve the efficient administration of ratepayer funding. We look forward to working with the Commission in refining the rules developed for NMEC programs and projects.

MCE and BayREN hereby submit comments on the Draft Revised Rulebook for Normalized Metered Energy Consumption ("Draft Revised Rulebook").[1] MCE and BayREN initially address the questions posed in the ruling and then provide broader comments on the appropriateness of the revised rules, request necessary clarifications, and recommend a number of improvements to the rulebook. MCE and BayREN believe that these comments will help align the rulebook more closely with the objectives of California Assembly Bill 802 ("AB 802") and ensure that new and innovative NMEC program designs can be developed under the rules of the Draft Revised Rulebook.

II. BACKGROUND

AB 802 directed the Commission to "authorize electrical corporations or gas corporations to provide financial incentives, rebates, technical assistance, and support to their customers to increase the energy efficiency of existing buildings based on all estimated energy savings and energy usage reductions, taking into consideration the overall reduction in normalized metered energy consumption as a measure of energy savings."[2] In response to AB 802, the Commission has authorized the creation of NMEC programming under the auspices of its ratepayer-funded energy efficiency framework, and has developed a rulebook to guide their design and implementation.[3]

The August 29 Ruling builds on prior rulings, including ALJ Fitch's March 23, 2018 ruling in Application 17-01-013 et al. and ALJ Kao's January 31, 2019 ruling in the same proceeding,

[1] Attachment A to the August 29 Ruling, Draft Rulebook for Programs and Projects Based on Normalized Metered Energy Consumption.
[2] AB 802, Section 6, amending Section 381.2(b) of the Public Utilities Code.
[3] Version 1.0 of the Rulebook was released on March 23, 2018.

as well as Commission Decision 18-01-004, dated January 11, 2018.[4] Following the January 31, 2019 ruling, Energy Division staff convened a Working Group focused on enabling population-level NMEC rules for third-party programs expected to launch in 2020.

III. COMMENTS ON THE SIX SUBJECTS ENUMERATED IN THE RULING

MCE and BayREN appreciate the invitation in the August 29 Ruling to comment on six enumerated subjects. We address each of the six subjects briefly here.

> *1. M&V Plans: The rulebook includes requirements for two types of M&V plans – a bid-level M&V Plan to be submitted by third-party bidders as part of their bid, and a program-level M&V plan to be developed by PAs for inclusion in Implementation Plan and advice letter submissions. Is there any additional information that should be required as part of either the bid-level or program-level M&V plans? And conversely, are any of the required items or requested detail unnecessary for inclusion?*

MCE and BayREN find the proposed requirements for program-level measurement and verification ("M&V") plans to be reasonable. However, the requirements for *bid-level* M&V plans are duplicative, particularly where a program-level M&V plan has previously been developed and incorporated into the specifications of the Request for Proposal.

The Draft Revised Rulebook lists three bid-level M&V requirements.[5] The first requirement is a description of the program target population and participant eligibility criteria. The second requirement is a documentation of the expected costs, energy savings and effective useful life ("EUL") of planned measures and intervention strategies. However, both of these requirements can reasonably be expected to be incorporated into the bidder's proposed

[4] ALJ Fitch's March 23, 2018 ruling invited comments on proposed requirements related to measurement and verification and proposed to sunset the filing process for High Opportunity Energy Efficiency Programs. ALJ Kao's January 31, 2019 ruling provided guidance in response to comments on certain measurement and verification issues raised by the March 23, 2018 ruling, acknowledged the two broad categories of NMEC, site-level and population-level, and confirmed that site-level NMEC would be classified as custom and follow a modified custom process review

[5] Draft Revised Rulebook at 11-12.

implementation plan and therefore would not need to be included in a separate bid-level M&V plan. The third requirement refers to the identification of the method(s) and calculation software that will be used to calculate savings. MCE and BayREN believe that this requirement is better addressed by the Program Administrator ("PA") in the program-level M&V plan because the PA should be responsible for vetting and specifying the methods and software used to calculate savings during program design. For these reasons, MCE and BayREN recommend eliminating the requirement for a bid-level M&V plan.

> *2. Population-level NMEC rules include program eligibility thresholds based on FSU levels – with an alternative advice letter option if those thresholds are not met. Is the threshold for FSU set at an appropriate level? If not, please provide alternative(s) and accompanying rationale. Are there other eligibility requirements, such as estimated percent savings or number of sites, that should be included for population-level NMEC programs?*

It is appropriate to base eligibility thresholds for population-level NMEC programs on fractional savings uncertainty ("FSU") levels and support a threshold of 25%.

> *3. Pay-for-Performance (P4P): Population-level NMEC rules include a 75 percent P4P threshold for PA program payments, with an alternative advice letter option if the threshold is not met. Is this P4P threshold appropriate? If not, please recommend a different P4P threshold and accompanying rationale, or another approach for ensuring that ratepayer funds are spent on programs that will yield cost-effective savings.*

While it is appropriate to set minimum pay-for-performance ("P4P") thresholds for program payments, MCE & BayREN caution against the Commission creating overly prescriptive rules for incentive design for NMEC programs that may limit new and innovative program designs. The Commission supported this general notion in D.18-05-041 by recommending that PAs should incorporate TURN's proposed policy recommendations on incentive design into their request for proposals for third-party implementation but stopping short of prescribing specific rules on incentive design. The Decision states:

> "TURN offers several general policy recommendations on incentive design, …, with which we agree and will require the PAs to use as high-level guidance for incentive design in their programs. These are all designed to maximize value for each dollar of ratepayer investment, without prescribing rules in every particular instance that a program design may encounter."[6]

Along those lines, MCE and BayREN recommend that PAs continue to have flexibility in determining the appropriate threshold for P4P payments under their programs through competitive solicitations and based on program design and varying incentive and implementation cost structures. Also, the use of AMI data and NMEC methods opens up additional opportunities to mitigate ratepayer risks in addition to the performance payment terms in question here.

If the Commission determined that it is appropriate to prescribe a particular P4P threshold for NMEC program payments, MCE and BayREN recommend that the optimal value of that threshold should be subject to further empirical testing and evaluation. This is because the incremental reduction in rate-payer risk between 75% and 50%, for instance, may be insignificant but may have profound impact on an aggregator's cash-flow, especially during this nascent phase.

Finally, MCE and BayREN respectfully request that any new threshold not be imposed retroactively on existing programs or programs already under development that have previously established thresholds. Previously negotiated contracts were developed in good faith based on the NMEC regulations then in place. To subject previously negotiated arrangements to after-the-fact Commission review and approval through the Advice Letter process would represent an undue regulatory risk that neither PA nor the selected program implementer should be asked to bear.

> *4. NMEC Methods and Software: The rulebook requires that any proprietary NMEC method or software used to determine payable or claimable savings must go through a custom approval process, and then the PA must submit an advice letter for the program specifying details of the proprietary method or software. NMEC methods and software that are public/ open source are not subject to this requirement. Is this requirement appropriate? If not, please provide alternative approach(es).*

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[6] D.18-05-041, Decision Addressing Energy Efficiency Business Plans, at 18.

Transparency, consistency, and credibility of the savings calculation methodology are paramount, particularly when implementer compensation is tied to performance. As such, MCE and BayREN agree that it is appropriate to require proprietary NMEC methods or software used to determine payable or claimable savings to go through a custom approval and advice letter process. Alternatively, open source software benefits from the advantages of full transparency, public input, and auditability for validation purposes. Therefore, it is appropriate to exempt public/open source NMEC methods and software from the advice letter process, because unlike proprietary software, its source code is disclosed and verifiable.

> *5. Should the guidance for PA-administered and implemented population-level NMEC programs be different than the guidance for population-level NMEC programs implemented by third-parties? If so, in what way(s)?*

The Commission should develop consistent guidance for PA-administered and implemented and third-party implemented population-level NMEC program to support replicability and market growth.

> *6. This version of the NMEC rulebook is intended to enable the first large batch of NMEC programs to launch successfully (beyond the limited number of current NMEC programs). What are the most critical items the Commission should consider for future NMEC program rules and policy?*

MCE and BayREN offer additional comments in Section IV that we believe are essential to align the Draft Revised Rulebook more closely with the objections of AB 802 and to ensure that new and innovative NMEC program designs can be developed under the proposed rules. Please refer to those further comments below.

IV. ADDITIONAL COMMENTS ON THE DRAFT REVISED RULEBOOK

In this section, MCE and BayREN provide supplemental comments and requests for important clarifications.

1. The Rulebook Should Expressly State the Scope of Its Applicability and Define NMEC Programs

The Draft Revised Rulebook should clarify the fundamental question: what qualifies as an NMEC program subject to the rules described in the Draft Revised Rulebook, as opposed to a program that uses NMEC as a savings quantification tool within an energy efficiency program? It is currently unclear when a program must be called a "NMEC Program" and subjected to compliance with these rules. Without clarity on these fundamental points, it will be challenging for EE PAs to know when they must comply with the rulebook, as opposed to when other rules, policies or procedures may govern their programs. A clear scope of applicability and definition of NMEC programs must be provided before the rulebook is approved. The Draft Revised Rulebook at page 22 defines the term "Normalized Metered Energy Consumption (NMEC)" but nowhere does the rulebook clearly define or state what programs utilizing NMEC as a tool to measure savings are subject to the rules therein. MCE and BayREN believe that it is of particular importance that the Commission provide more transparency around the rules for behavioral programs and clarify the distinction between behavioral and NMEC programs. For example, it is currently unclear if a population-level behavioral program that is measuring savings at the meter is classified a "NMEC program" that falls under the rules of the Draft Revised Rulebook.

2. The Draft Revised Rulebook Should Permit Both Opt-In and Opt-Out NMEC Program Designs

The Draft Revised Rulebook inappropriately restricts population-level participation in NMEC programs to an "opt-in" program design.[7] Whereas opt-in may be more appropriate for site-level NMEC programs, this requirement would substantially undermine a key promise of population-level NMEC programs. Population-level NMEC programs aim to efficiently target

[7] Draft Revised Rulebook at 4, Section I.B.

customers and accurately quantify savings across a large population, and are especially important in serving customer segments that are otherwise extremely difficult to serve cost-effectively (e.g. residential customers). In combination with randomized controlled trials ("RCT"), population-level NMEC is a transparent and appropriate method for quantifying savings for opt-out programs.

In addition, opt-in programs as a general rule are self-selecting, smaller and comprised of more technology and energy efficiency adopters than the general population. For this reason, requiring participants to opt-in to the program will limit some of the potential benefits of population-level NMEC, namely, reaching a wider customer group with strong program participation in support of a cost-effective program with statistically significant outcomes, as provided for by AB 802.

Finally, the Draft Revised Rulebook does not provide any explanation or rationale for imposing an opt-in requirement and it does not state why opt-out programs are inadequate or otherwise inappropriate. If the Commission deems an opt-in requirement is necessary, it should provide its reasoning for this position. In the absence of a well-justified basis for restricting NMEC programs to opt-in only, the restriction on page 4, Section I.B. should be stricken, and a definition of "opt-out" should be added to the Draft Revised Rulebook at page 23.

3. The Commission Must Develop Distinct Rules for Qualifying Measures for Population-Level NMEC Programs

With respect to qualifying measures, the Draft Revised Rulebook establishes that population-level behavioral NMEC programs will be subject to "the site-level NMEC requirements at Section II.1.B.E.2 of this rulebook."[8]

[8] Draft Revised Rulebook at 12. MCE and BayREN would like to point out that we believe this reference should be updated to read "Section II.1.E.2".

However, population-level NMEC programs are substantially different from site-level NMEC programs, especially with regard to behavioral measures. Behavioral savings under a population-level program should not be treated in the same way as site-level behavioral interventions. In general, broad-based residential behavioral program participants are not as sophisticated as non-residential customers, who may even have energy or facility managers dedicated to maximizing savings potential. In contrast, population-based programs are designed to maximize benefits across populations who are not experts or aware of energy efficiency opportunities. Because of the substantial differences between these two types of behavioral programs, they should not be subjected to the same rules of practice.

MCE and BayREN strongly recommend that the Commission develop distinct rules for qualifying measures for population-level NMEC programs that are appropriate for all types of population-level NMEC programs.

4. The Commission Should Clarify the Length, Applicability, and Intent of the Proposed Repair and Maintenance Agreement

The long-term repair and maintenance agreement proposed in the Draft Revised Rulebook should be clarified and amended to ensure that it does not hinder program adoption and implementation. The Draft Revised Rulebook currently requires that "[t]he program participant or project owners must commit to a repair and maintenance plan for a minimum of three years via a signed customer agreement…".[9] It is uncertain whether this requirement applies only to repair and maintenance measures, or whether it is also intended to apply to other types of behavioral, retro-commissioning, and operational programs. Further, language on the prior page of the Draft Revised Rulebook, in the section on payments, seems to specify a two-year contract requirement

[9] At 9, Section II.1.E, applicable to site-level NMEC and apparently also to population-level behavioral NMEC programs, see discussion above.

rather than three years for some programs. That section states that "[i]ncentives for behavioral, retrocommissioning, and operational measures shall only be paid once participant commits to a maintenance plan for a minimum of two years…"[10]

In addition, it is unclear whether the requirement is intended to equate to a three-year (or two-year) estimated useful life for all behavioral, retro-commissioning, and operating programs. The Commission should clarify the intent of these requirements, as well as the potential inconsistency as to a two-year versus a three-year requirement, so that MCE and other stakeholders can accurately provide shareholder feedback

5. The Reporting Project Coordination Group is the Correct Forum to Develop a Proposal for a NMEC Savings Claim Process

MCE and BayREN recommend that the savings claim process be amended to better align with the current reporting paradigm. At present, the Draft Revised Rulebook provides that "[f]inal savings claims may be filed only after the 12-month post-intervention monitoring period has ended and the M&V has been completed and finalized."[11] The process described here for site- and program-level NMEC programs does not align with the current reporting paradigm. This misalignment will result in skewed cost effectiveness calculations under the Total Resource Cost ("TRC") test, due to a misalignment between costs and energy savings. More specifically, administrative, measure cost and initial incentive payment costs will incur before the final incentive payment and NMEC savings are only known 12-months post-installation.

MCE and BayREN believe that this important topic merits further discussion and recommend that the savings claim process for both site-level and population-level NMEC

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[10] At 8, Section II.1.D.5, regarding payments and incentives.
[11] Draft Revised Rulebook at 16.

programs be discussed and amended in the Reporting and Data Management Project Coordination Group ("PCG")[12] not as a part of this ruling to update the NMEC Rulebook.

6. Existing NMEC Programs and NMEC Programs or Projects Already under Development Must Be Grandfathered

MCE has been developing and contracting for a population-level single-family NMEC program since the beginning of 2019. BayREN has been developing a population-level small-medium businesses NMEC program since 2016. BayREN has completed two solicitations, and it is in the process of contracting with an aggregator. While MCE and BayREN are supportive of the Commission's initiative to streamline the rules and requirements for NMEC programs and projects that use NMEC savings calculations, MCE and BayREN also strongly urge the Commission to grandfather programs and projects that are already under development or have already been implemented before the final Ruling approves the Draft Revised Rulebook. It would be unjust and unfair to impose rules that were not noticed and approved in advance to existing programs, projects and initiatives as the rules under the Draft Revised Rulebook could, likely inadvertently, hinder the implementation of programs and projects that are already underway and to which PAs have dedicated significant time and ratepayer funds.

Administrative Law Judge ("ALJ") Kao provided clarification by electronic mail to the service list on September 18, 2019, indicating that the Commission intends to finalize the draft NMEC rulebook via ruling after receipt and review of party comments, and clarifying that the

[12] The Reporting and Data Management Project Coordination Group was created in 2013 by CPUC-Energy Division staff to discuss reporting and data management specifications to accommodate policy objectives. The PCG is comprised of staff from the Commission's Energy Division, EE PAs and their consultants. Supported by subject matter experts and with a robust, results-oriented agenda, the PCG develops data reporting specifications to accommodate policy objectives such as NMEC. Additionally, the PCG discuss issues related to cost-effectiveness, timing of approved values, evaluations, and topics that impact data management. The meetings are generally open to a wide variety of stakeholders.

rulebook will not be effective until a ruling deems it so.[13] MCE and BayREN respectfully request the Commission confirm in the final Ruling that the Draft Revised Rulebook and the rules mentioned therein will only become effective after the ruling deems it so AND that all existing NMEC programs and programs already under development when the Draft Revised Rulebook becomes effective will be grandfathered in.

7. A Standing Working Group Could Aid with Future Revisions Processes

The Draft Revised Rulebook indicates that the Commission intends to update the rulebook periodically.[14] In order to ensure continuity, transparency, and an enhanced stakeholder input process, MCE and BayREN recommend that a standing working group be convened by the Commission on a regular or periodic basis to assist with future revisions to the NMEC rules. Issues that could be discussed by the working group to streamline the NMEC program process and encourage program innovation while protecting ratepayer funds include (but are not limited to):

1. Refining the rules for site-specific NMEC programs, given many of the existing site-specific NMEC rules are still overly burdensome and too similar to custom project rules, and consequently hinder program innovation.
2. Consistent with the Commission's preference for open-source NMEC solutions (which we whole-heartedly support), the Commission should invest in the development and proper function of institutions capable of maintaining and further refining open-source methods.

The Commission could also consider incorporating the issues related to further development of NMEC program and project rules under the existing Energy Market Methods

[13] Email of Administrative Law Judge Kao to service list in R.13-11-005, Sept. 18, 2019.
[14] Draft Revised Rulebook at 4.

Consortium (EM2). EM2 has been established to develop methods and standards to quantify metered energy savings and related grid impacts and support their adoption in the marketplace through programs and procurements. The organization brings together stakeholders and practitioners from around the nation to collaborate on maintaining and enhancing the open source CalTRACK methods. Through EM2, the Commission could support research in several important areas affecting the NMEC methodology, such as:

1. Estimating life-cycle savings persistence via whole-building NMEC analysis in lieu of measure-level EUL aggregation and reporting.
2. Improve methods of time-dependent valuation of energy savings to better support alignment between program impacts and grid requirements.
3. Technical and methodological barriers to enabling secure data sharing and overcome privacy concerns in support of demand side energy programs. Analysis results would support:
    a. Consistent methods for secure data transfer within pay for performance market applications
    b. Use cases to support market access to site level energy consumption data, without violating individual privacy rules, including forecasting, carbon accounting, energy modeling, comparison groups, etc.

V. CONCLUSION

MCE thanks Commissioner Randolph, Administrative Law Judge Fitch, and Administrative Law Judge Kao for their thoughtful consideration of these comments.

//

Respectfully submitted,

/s/ Jana Kopyciok-Lande

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September 30, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2019 and 2020 Compliance Years.	Rulemaking 17-09-020 (Filed September 28, 2017)

MARIN CLEAN ENERGY
3-DAY ADVANCE NOTICE OF EX PARTE COMMUNICATION

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September 20, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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MARIN CLEAN ENERGY
3-DAY ADVANCE NOTICE OF EX PARTE COMMUNICATION

Pursuant to Public Utilities Code Section 1701.1(e)(3) and Rules 8.3 and 8.4 of the California Public Utilities Commission's Rules of Practice and Procedure, Marin Clean Energy ("MCE") hereby provides advance notice of its scheduled *ex parte* communication with Adenike Adeyeye, Chief of Staff to Commissioner Guzman-Aceves. MCE's scheduled *ex parte* communication will be conducted orally, with no written materials provided. The meeting will occur in-person, at approximately 2:00 PM at the offices of the California Public Utilities Commission, located at 505 Van Ness Avenue, San Francisco, California on September 27, 2019. MCE initiated this communication. The following individuals will participate in the *ex parte* communication for MCE: Dawn Weisz, MCE CEO; Nathaniel Malcolm, Policy Counsel; and Brian Goldstein, Pacific Energy Advisors Chief Principal Consultant.

Respectfully submitted,

/s/ Daniel Settlemyer

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September 20, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
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September 18, 2019

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Respectfully submitted,

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September 18, 2019

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September 18, 2019

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Pursuant to Public Utilities Code Section 1701.1(e)(3) and Rules 8.3 and 8.4 of the California Public Utilities Commission's Rules of Practice and Procedure, Marin Clean Energy ("MCE") hereby provides advance notice of its scheduled *ex parte* communication with Yulia Schmidt, Advisor to Commissioner Rechtschaffen. MCE's scheduled *ex parte* communication will be conducted orally, via telephone, on September 23, 2019 at approximately 2:30 PM, with no written materials provided. MCE initiated this communication. The following individuals will participate in the *ex parte* communication for MCE: Dawn Weisz, MCE CEO; Nathaniel Malcolm, Policy Counsel; and Brian Goldstein, Pacific Energy Advisors Chief Principal Consultant.

Respectfully submitted,

/s/ Daniel Settlemyer

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September 18, 2019

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MARIN CLEAN ENERGY
AMENDED 3-DAY ADVANCE NOTICE OF EX PARTE COMMUNICATION

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October 2, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2019 and 2020 Compliance Years.	Rulemaking 17-09-020 (Filed September 28, 2017)

MARIN CLEAN ENERGY
AMENDED 3-DAY ADVANCE NOTICE OF EX PARTE COMMUNICATION

Pursuant to Public Utilities Code Section 1701.1(e)(3) and Rules 8.3 and 8.4 of the California Public Utilities Commission's Rules of Practice and Procedure, Marin Clean Energy ("MCE") hereby provides advance notice of its rescheduled *ex parte* communication with Leuwam Tesfai, Chief of Staff to Commissioner Shiroma. MCE's scheduled *ex parte* communication will be conducted orally, with no written materials provided. The meeting will occur in-person, at the offices of the California Public Utilities Commission, located at 505 Van Ness Avenue, San Francisco, California on October 04, 2019. The meeting was initially scheduled for October 2, 2019, but was rescheduled on October 1, 2019 at the request of Commissioner Shiroma's staff. MCE initiated this communication. The following individuals will participate in the *ex parte* communication for MCE: Dawn Weisz, MCE CEO; Nathaniel Malcolm, Policy Counsel; and Brian Goldstein, Pacific Energy Advisors Chief Principal Consultant.

Respectfully submitted,

/s/ Daniel Settlemyer

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October 2, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
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MARIN CLEAN ENERGY
NOTICE OF EX PARTE COMMUNICATION

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October 1, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2019 and 2020 Compliance Years.	Rulemaking 17-09-020 (Filed September 28, 2017)

MARIN CLEAN ENERGY
NOTICE OF EX PARTE COMMUNICATION

Pursuant to Rule 8.4 of the California Public Utilities Commission's ("Commission") Rules of Practice and Procedure, Marin Clean Energy ("MCE") hereby provides notice of the following *ex parte* communication with Adenike Adeyeye, Chief of Staff to Commissioner Guzman Aceves. MCE's scheduled *ex parte* communication was in-person, and no written materials were provided. The meeting occurred at 2:00 p.m. on September 27, 2019 and lasted approximately 30 minutes. The meeting took place at the California Public Utilities Commission offices in San Francisco, California. MCE initiated this communication. The following individuals participated in the *ex parte* communication for MCE: Dawn Weisz, MCE CEO; Nathaniel Malcolm, MCE Policy Counsel; and Brian Goldstein, Pacific Energy Advisors Chief Principal Consultant.

During the meeting, MCE discussed the September 6, 2019 Proposed Decision ("PD") issued in Rulemaking 17-09-020 regarding import Resource Adequacy ("RA"). Ms. Weisz asserted that the PD mischaracterizes the import RA changes as mere clarifications to existing import RA rules. Ms. Weisz, Mr. Malcolm, and Mr. Goldstein explained that the PD fundamentally changes the import RA requirements by switching from a "must offer" obligation in the day-ahead market to a "must flow" obligation during the Availability

Assessment Hour ("AAH"). Such changes are likely to: (1) disrupt the California Independent System Operator's ("CAISO") ability to economically dispatch resources; (2) risk oversupply during the AAH; (3) cause curtailment of in-state renewables; and (4) frustrate the state's greenhouse gas-reduction efforts.

Additionally, Ms. Weisz asserted that the PD, if adopted, would significantly destabilize the RA market by undermining existing import RA contracts between Load Serving Entities ("LSE") and importers weeks before the 2020 Year-Ahead Compliance deadline. The last-minute rule change would likely result in LSEs falling out of compliance at the "11th Hour" and lead to contract terminations due to change-of-law provisions in existing contracts. Beyond a compliance shortfall, however, the latter would risk an RA shortage and CAISO not having sufficient resources to call upon. Moreover, such contract terminations will likely lead to: (1) increased prices for both in-state and out-of-state RA; (2) increased costs for ratepayers; (3) increased instability and confusion in an already tight RA market; (4) increased shortages in the RA market; and (5) an unreasonable imposition of financial and non-compliance risk on LSEs.

Ms. Weisz also raised concerns about the effects of last-minute rule changes in general, including market disruptions and inefficiencies, increased costs, and stranded costs. She raised concerns that such changes are becoming more common and urged the Commission to refrain from making last-minute rule changes that impact and destabilize the market.

Mr. Malcolm and Ms. Weisz noted that the PD also raises concerns as to whether the rule changes discriminate against interstate commerce in violation of the Commerce Clause of the U.S. Constitution. Mr. Malcolm also raised concern that the proposed rule changes would implicate Federal Energy Regulatory Commission ("FERC") jurisdiction and potentially lead to increased FERC involvement in California's RA program.

MCE urged the Commissioner's Office to table the PD and instead coordinate closely with the CAISO in its existing stakeholder initiative addressing the import RA issue. Doing so would enable the CAISO and the Commission to more clearly identify: (1) the precise problem at issue; (2) the magnitude of the problem; and (3) a measured solution that would not bring unnecessary instability to the RA market.

At a minimum, MCE requested the Commission revise the PD to include a grandfathering provision that would allow any import RA contracts executed up the adoption of the Final Decision to count towards an LSE's RA compliance requirements.

Respectfully submitted,

/s/ Daniel Settlemyer

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October 1, 2019

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NOTICE OF EX PARTE COMMUNICATION

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September 26, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2019 and 2020 Compliance Years.	Rulemaking 17-09-020 (Filed September 28, 2017)

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Respectfully submitted,

/s/ Troy Nordquist

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September 26, 2019

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Respectfully submitted,

/s/ Troy Nordquist

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September 26, 2019

**BEFORE THE PUBLIC UTILITIES COMMISSION
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RESPONSE OF MARIN CLEAN ENERGY TO THE PETITION FOR MODIFICATION OF DECISION 19-02-022 BY PACIFIC GAS AND ELECTRIC COMPANY (U 39 E)

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September 19, 2019

TABLE OF CONTENTS

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2019 and 2020 Compliance Years.	Rulemaking 17-09-020 (Filed September 28, 2017)

RESPONSE OF MARIN CLEAN ENERGY TO THE PETITION FOR MODIFICATION OF DECISION 19-02-022 BY PACIFIC GAS AND ELECTRIC COMPANY (U 39 E)

Pursuant to Rule 16.4(f) of the California Public Utilities Commission's ("Commission") Rules of Practice and Procedure and the *Email Ruling Granting PG&E's Motion to Shorten Time to Respond with Modifications* ("Email Ruling") issued September 12, 2019, Marin Clean Energy ("MCE") timely responds to *The Petition for Modification of Decision of Decision 19-02-022 by Pacific Gas and Electric Company (U 39 E)* ("Petition") filed on September 11, 2019.

MCE objects to Pacific Gas and Electric Company's ("PG&E") Petition because of an estimated **$18 million** impact to MCE (representing approximately 6% of MCE's annual budget) and other potential impacts to other Load Serving Entities ("LSE") that have relied on and procured to the Commission's newly adopted "PG&E Other" Local Capacity Area ("LCA") disaggregation rule. To grant the Petition's requested relief at this late point in the 2020 Year-Ahead Resource Adequacy ("RA") compliance cycle incentivizes non-compliance, undermines the integrity of the Commission's own rules, and penalizes good actors.

I. INTRODUCTION

MCE contests PG&E's Petition and objects to a reduced public review and comment period on a proposed decision on the Petition. Approval of PG&E's Petition days before the 2020 Year-Ahead compliance deadline would be procedurally improper and harmful to MCE.

Approval of PG&E's Petition would have a substantial financial and anti-competitive impact on Load Serving Entities ("LSE") that have successfully procured to the existing rules. The Commission, in Decision ("D.") 19-02-022, adopted the current "PG&E Other" LCA disaggregation rule and directed LSEs to comply with the rule in their 2020 Year-Ahead Compliance filings or file a waiver using the existing Commission process.[1] It would be imprudent and prejudicial for the Commission to deviate from its own rules days or even weeks before the end of a compliance period to grant an Investor Owned Utility ("IOU") special relief from its compliance obligations.

Instead, the Commission should defer conclusions about the need for "PG&E Other" LCA rule changes until it evaluates how the newly adopted disaggregation rules play out in the 2020 Year-Ahead Compliance filings. The results of these filings will help determine the issues and inform Energy Division's Staff report that will be issued within 60 days of the compliance deadline.[2] Thus, any rule revisions can be tailored to address empirically identified problems.

II. MCE CONTESTS PG&E'S PETITION AND OBJECTS TO THE REDUCED PUBLIC REVIEW PERIOD ON THE PROPOSED DECISION

Administrative Law Judge Chiv's Email Ruling issued on September 12, 2019 directed a responding party to indicate in its response whether (1) the party contests PG&E's Petition and (2) whether the party objects to a reduced public review and comment period on a proposed decision

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[1] *See* D.19-02-022, Ordering Paragraphs ("OP") 12, 13, and 14.
[2] *Id.*, OPs 16 and 17.

on the Petition. For the reasons outlined herein, MCE both contests the Petition and objects to the reduced public review period on the proposed decision.

III. PG&E'S LAST-MINUTE RULE CHANGE REQUEST WOULD HAVE A MATERIAL FINANCIAL IMPACT ON MCE AND ITS CUSTOMERS

Last-minute rule changes have material financial consequences for LSEs and send confusing signals to the marketplace. Indeed, MCE's CEO, Dawn Weisz, referred to the financial impact of last-minute changes to RA requirements at the Senate Energy Committee hearing on March 19, 2019 and at a December 19, 2018 meeting with Energy Division staff.[3] The Commission must acknowledge that MCE and other LSEs have relied on the new disaggregation rules in making significant investments in "PG&E Other" LCA resources. Granting PG&E's Petition in the days leading up to the October 31, 2020 Year-Ahead Compliance deadline would likely undermine such investments. Granting the Petition would also undermine LSEs' diligent efforts to secure most if not all of their "PG&E Other" LCA RA, in many cases at a market premium. Such LSEs would not have the luxury of taking advantage of the last-minute relief sought by PG&E, notably a relief that cures PG&E of a potential deficiency and frees PG&E from the costs associated with strict compliance with the disaggregation rule.

If the Commission grants PG&E the regulatory relief requested, that regulatory action would also send signals to the marketplace that could undermine the Commission's intent to ensure that resources get picked up in highly constrained areas. Non-compliant LSEs could then rely on lower priced RA resources –resources not available prior to the requested rule change– that meet the "PG&E Other" LCA aggregated requirement, but may be considered "less effective" because

[3] Ms. Weisz testified that MCE incurred more than $400,000 in stranded costs due to a last-minute increase in MCE's Reliability Must Run offsetting Local RA allocation 7 days after the 2019 Year-Ahead Compliance deadline.

they are not located in the more constrained local areas. Such a result would undermine the Commission's reason for the disaggregation rule in the first place.

Moreover, LSEs that have attempted to meet, or have met, the new requirements would be negatively impacted financially when competing with PG&E. Such LSEs would likely be unable to sell off the secured resources at the premium prices they paid, if sellable at all. MCE's customers, and customers served by similarly situated LSEs, would have to bear the costs of compliance with the existing rules, while PG&E's bundled ratepayers would potentially get relief from bearing costs associated with higher "PG&E Other" LCA resources.

To illustrate MCE's immediate concern, MCE executed a number of RA contracts specifically tailored to meet the new RA compliance requirements: the new 3-year forward Local RA and "PG&E Other" LCA disaggregation rules. As indicated above, some of these commitments were secured at a premium. MCE estimates that these commitments represent future RA costs upwards of $18 million; costs that were incurred in reliance on the newly adopted disaggregation rule. Approval of PG&E's Petition will likely result in stranded and unnecessary costs being shouldered solely by MCE's customers. Given the abbreviated time frame, MCE is still examining potential legal remedies should the proposed rule change occur.

IV. PG&E'S LAST-MINUTE RULE CHANGE WOULD MAKE MATERIAL CHANGES TO "PG&E OTHER" LCA RULES DAYS BEFORE THE COMPLIANCE DEADLINE WITHOUT A SUPPORTING RECORD

A. The Data Supporting the Need for a Last-Minute Rule Change Has Not Been Vetted or Supported By the Record in the RA Proceeding.

PG&E's Petition contains significant information that has not been examined in the RA proceeding. Parties other than PG&E should also have the opportunity to provide their research and market activities that may or may not demonstrate different conclusions than PG&E. Without an adequate record validating or contradicting PG&E's concerns, the Commission could risk providing a market relief mechanism that could have unintended consequences on "PG&E Other" LCA resource availability, resource valuation and effectiveness, and market efficiencies in the long-run.

B. The Underlying Need for the Petition May Be Driven, In Part, by Circumstances Unique to PG&E.

There may be circumstances unique to PG&E that only impact PG&E's ability to procure "PG&E Other" LCA resources; such circumstances are not necessarily applicable to other LSEs. One such circumstance could be PG&E's current credit rating status, which has been downgraded in light of its bankruptcy filing and wildfire liabilities. As such, PG&E's inability to procure "PG&E Other" LCA RA could be directly linked to its financial difficulties, and may or may not be directly associated with the larger market inefficiency PG&E asserts in its Petition. This issue could be further evaluated in the RA proceeding to accurately determine the drivers of the perceived "PG&E Other" Local RA shortage to determine with more certainty which rule changes would best address the issues.

C. There Is an Existing Commission Waiver Process for an LSE to Use If It Cannot Meet Its Local RA Requirements.

The Commission has a long-standing process LSEs may use in the event they expect to be non-compliant with their Local RA requirements; a process other LSEs, including IOUs, Community Choice Aggregators, and Electric Service Providers, have followed in past compliance years. PG&E can and should utilize this same established process if it is unable to meet its "PG&E Other" LCA requirements.

If PG&E is correct that the disaggregation of "PG&E Other" LCA has led to an inefficient market, such a conclusion may be supported by PG&E's and other LSEs' waivers. If the Commission indeed receives a high number of waiver requests for the 2020 Year-Ahead

Compliance filing, this will provide some verifiable market basis for the Commission to review the "PG&E Other" LCA rules and inquire further as to whether LSEs' waivers are indeed tied to the disaggregation rules –a presumed purpose of the Energy Division RA report directed by D.19-02-022. As such, the Commission will have the opportunity to identify the true drivers of the problem and adopt appropriate rule changes for all LSEs well in advance of a future Year-Ahead Compliance filing deadline.

D. It Would Be Imprudent for the Commission to Change Course This Late in the 2020 Year-Ahead Compliance Period.

MCE cautions the Commission not to rush to grant PG&E's Petition so close to the compliance filing deadline. Despite the limited record discussion of the impacts of disaggregation of "PG&E Other" LCA,[4] the Commission nonetheless directed disaggregation of "PG&E Other" LCA, and LSEs were directed to procure accordingly. It would be imprudent for the Commission to prejudge and preempt the effects of the disaggregation rule in the "11th Hour" of this compliance period without any record evidence that the rule adopted is empirically problematic. The Commission should refrain from unnecessary rule changes until after the results of this compliance period are available and evaluated in the RA proceeding. An uninformed last-minute rule change unsupported by a robust and vetted record could lead to: unintended consequences in the Local RA market; exempting PG&E from meeting its compliance requirements while undermining investments other LSEs made in their efforts to comply with the existing rules; and creation of a precedent for LSEs to ask for waivers outside the established Commission procedures.

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[4] As PG&E notes in its Petition, discussion of "PG&E Other" LCA disaggregation was not included in the original proposed decision for D.19-02-022 issued on November 21, 2018. The disaggregation of "PG&E Other" LCA was included in a revised agenda decision issued on February 15, 2019. Parties did not have a procedural opportunity to comment on the issue prior to the Commission voting out D.19-02-022.

As such, the Commission should not grant PG&E its requested relief. Denying the Petition will ensure all LSEs and their customers are similarly situated, exposed to the same market dynamics and challenges, and have equal access to the same regulatory relief mechanisms.

V. CONCLUSION

MCE thanks Assigned Commissioner Randolph and Assigned Administrative Law Judges Chiv and Allen for the opportunity to provide this response to PG&E's Petition.

Respectfully submitted,

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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Building Decarbonization.	)))))	Rulemaking 19-01-011 (Filed January 31, 2019)

OPENING COMMENTS OF THE JOINT COMMUNITY CHOICE AGGREGATORS ON STAFF PROPOSAL FOR BUILDING DECARBONIZATION PILOTS

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Building Decarbonization.	)))))	Rulemaking 19-01-011 (Filed January 31, 2019)

OPENING COMMENTS OF THE JOINT COMMUNITY CHOICE AGGREGATORS ON STAFF PROPOSAL FOR BUILDING DECARBONIZATION PILOTS

In accordance with the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission") and as directed in the July 16, 2019 *Administrative Law Judge's Ruling Seeking Comment* ("Ruling"), Marin Clean Energy ("MCE"), Sonoma Clean Power Authority ("SCP"), Peninsula Clean Energy ("PCE"), and Silicon Valley Clean Energy Authority ("SVCE") (collectively, the "Joint CCAs") hereby submit the following opening comments on the *California Public Utilities Commission and California Energy Commission Staff Proposal for Building Decarbonization Pilots – Draft* ("Staff Proposal") included as Attachment A to the Ruling.

I. INTRODUCTION

The Joint CCAs appreciate the Commission's diligence in implementing Senate Bill ("SB") 1477 and broadly investigating strategies and frameworks to achieve deep reductions in greenhouse gas ("GHG") emissions from buildings. As non-profit agencies that do not derive revenues from gas sales, Community Choice Aggregators ("CCA") are poised to help deliver building decarbonization programs in the areas they serve. Since the Joint CCAs are local government agencies, we are uniquely responsive to the needs of our local communities, including community goals for local energy, resilience, and decarbonization. Furthermore, many

CCAs are currently offering or in the process of designing decarbonization programs aligned with the goals of SB 1477. Examples include MCE's LIFT program, which offers heat pump water heater incentives to low-income customers, SCP and MCE's Advanced Energy Rebuild Program, offering incentives to all-electric new construction homes, and SVCE's incentive for heat pump water heater retrofits.

II. GENERAL COMMENTS

The Joint CCAs support the Commission's dedication to reducing GHG emissions through the Building Initiative for Low-Emissions Development ("BUILD") and Technology and Equipment for Clean Heating ("TECH") programs. A number of CCA programs, including MCE supported SB 1477, and believe that the BUILD and TECH program pilots outlined in the Staff Proposal are important first steps in achieving the state's building decarbonization and greenhouse gas ("GHG") emissions reductions goals.

The Joint CCAs generally support the Staff Proposal, but believe that further refinement in certain areas would be beneficial. Specifically, for both the BUILD and TECH programs, the Staff Proposal should specifically require that funding be allocated in a fair and neutral manner among the customers of various categories of LSEs, and that projects in CCA programs' service territories receive fair access to program funds. Since CCAs are particularly aligned to the needs of the communities we serve and work with other local agencies that serve the target communities, the Joint CCAs are especially well situated to carry out the goals of the BUILD and TECH programs.

III. RESPONSES TO SPECIFIC QUESTIONS

Question 3:

> *Are the annual budgets proposed for the BUILD and TECH programs reasonable? Why or why not?*

Response to Question 3:

The Staff Proposal sets a total budget of $50 million per year for the BUILD and TECH programs, with 40% ($20 million) going to the BUILD program, and 60% ($30 million) going to the TECH program. Program budgets would be allocated as follows:

BUILD Program ($20 million/year):

- $6 million for low income / disadvantaged community ("DAC") residential housing.
- Up to $2 million reserved for CEC program administration.
- $1.5 million budgeted for low-income technical assistance.

TECH Program ($30 million/year):

- $5 million for a grant program to pilot innovative ideas.
- $2 million for a competitive prize program.
- $2 million for evaluation of both the BUILD and TECH programs.
- Roughly $22 million for general program operating expenses.

The Joint CCAs believe that the proposed budgets are generally appropriate but, could benefit from several further refinements at a more granular level. First, while the BUILD Program includes a clear cap on program administrative costs (no more than 10% of the total budget), the TECH Program budget does not include a similar cap. It would be reasonable for the Commission to adopt the same 10% administrative cost cap total for both the TECH Program as a whole.

Second, while the Joint CCAs think that the proposed prize program is an interesting idea in theory, as a practical matter these funds could be better spent on either incentives or "quick start" grants. While grants and incentives can be specifically directed at innovations and new approaches, the Joint CCAs have concerns that the prize program will actually reward existing strategies that can be rapidly ramped up, rather than new and possibly superior approaches, which may be slower to develop. The Commission should also consider whether the budgets for the "quick start" grants and the prize programs should be shaped over the 3-year duration of the pilot program, rather than using a flat budget of $5 million for the grants and $2 million for the prize per year. As the grants are designed to be quick start, it is conceivable that a larger portion of the funds for the grants would be desired in year 1, and a smaller amount in year 3. Likewise, if the Commission wishes to explore prize funding, it would make more since to do so in year 3, after the quick start grants have been prioritized in years 1 and 2 and have promoted innovative approaches to the point of being able to scale up quickly.

Third, the current proposal would allocate the evaluation costs for both the BUILD and TECH programs to the TECH program budget. This may make sense from a contracting perspective if the evaluation for both programs is anticipated to be completed through a single evaluation. However, it is confusing since it does not reflect the actual costs associated with evaluating each program. The BUILD program's share of evaluation costs should be subtracted from the TECH program budget and allocated to the BUILD program.

Finally, the Joint CCAs support the Low Income/ Disadvantaged Communities Set Aside. Given that adoption of low GHG emission technologies is likely to proceed far faster in wealthier communities, achieving broad-based benefits and full decarbonization will need to involve significant support for low income and disadvantaged communities that will otherwise be far slower to adopt these technologies. By the same token, the Joint CCAs support the technical assistance for low-income housing developers.

Question 4:

Is the proposed budget allocation of 40 percent of the budget for the BUILD program and 60 percent for the TECH program appropriate? Why or why not?

Response to Question 4:

In light of current new housing development rates in California, the Joint CCAs agree with the split of 40% towards BUILD and 60% towards TECH. The Joint CCAs view TECH as the more important program up-front to deal with the state's large existing building stock, while BUILD will drive market transformation to ensure long-term success of the State's decarbonization efforts. As developers become more familiar with building all-electric homes and related technologies achieve increased market penetration, it may make sense to transition more of the funding towards TECH to further address California's existing building stock. However, until the all-electric segment of the industry is more mature, the programs should primarily focus on developing expertise can be leveraged well beyond the scope of the direct funding of the BUILD program into market transformation. As such, the Commission should consider mechanisms for adjusting the budget allocation between BUILD and TECH on a regular basis.

Question 5:

> *Is it appropriate for the CPUC to select the CEC as the administrator of the BUILD program? Why or why not?*

Response to Question 5:

The Joint CCAs strongly believe that any program administrator must: 1) be a neutral party with no biases towards or against any interested party or parties; and 2) the BUILD program administrator must have the experience and capacity to manage a statewide program like BUILD. The Joint CCAs view the California Energy Commission ("CEC"), an established, neutral regulatory agency with the expertise, capacity, and proven ability to administer programs like BUILD, as an ideal choice to be the BUILD program administrator. Furthermore, the ability of the CEC specifically to coordinate with Title 24 standards and the development of reach codes suggests that the CEC is uniquely well suited to this role.

Question 6:

Are the proposed elements of the BUILD program reasonable and sufficiently comprehensive? If not, what elements should be removed, changed, or added? Specific questions to consider:

a. *Given that production builders (e.g., builders who build houses, townhouses, condos, and rental properties on land owned by a building firm) construct the majority of new homes in California, should BUILD incentives be offered separately for each new home or collectively for each new subdivision?*
b. *Should BUILD incentives be offered on a first-come first-served basis across the state, or should BUILD incentives be limited to the regions of the state where the largest GHG emission reduction potentials exist? Or should it be based on some other standard? Please explain your rationale.*
c. *Should each developer or builder have a limit on the total share of incentive dollars received per year, or overall?*
d. *What is the appropriate incentive level for the BUILD program?*

<u>Response to Question 6(a)</u>:

Both production builders and custom home builders should qualify for and have access to BUILD funding. Although it is true that a significant share of new housing in California is constructed by production builders, in the wake of recent wildfires a significant number of the new, entirely rebuilt replacement homes are being built by custom builders. Further, it appears that these custom builders may have a higher all-electric adoption rate than production builders – in the Advanced Energy Rebuild Program, SCP is finding a higher acceptance of all-electric homes with custom home builders. BUILD must have a pathway to accommodate these builders. Given the relatively small BUILD budget size, the Joint CCAs are concerned that a significant share of the yearly program budget could be taken up by a handful of large developments. In implementing BUILD, the CEC should seek to ensure that funding is available and allocated in a balanced manner to small developments and custom homes as well as large developments.

<u>Response to Question 6(b)</u>:

The Joint CCAs support the first-come, first-serve model combined with an incentive adder for regions of the state with the largest GHG-reduction potential. Funds should not be limited to only certain jurisdictions or Load Serving Entity ("LSE") service territories, and it is essential that projects in CCA programs' service areas have fair access to BUILD funds.

Response to Question 6(c):

The Joint CCAs do not support a builder or developer cap in the first year of the program, although this should be revisited in subsequent years if a builder or developer (or group of builders or developers in a specific region or LSE territory) is receiving a disproportionate share of BUILD funding.

Response to Question 6(d):

The Joint CCAs recommend that the Commission consider incentives adequate to stimulate the market and deployment of eligible technologies, which may or may not be greater than the social cost of carbon. The social cost of carbon is a reasonable cost metric for the deployment of carbon reducing technologies once markets and technologies are mature, but at this initial phase incentivizing development may well take higher levels of incentives to have the impacts intended for the program. While decarbonization strategies overall would ideally cost less than the social cost of carbon, the reality is that the early edge of any new technology costs more than the eventual average costs until efficiencies bring the costs down in later phases of the adoption process. Thus, these early stage programs should not be overly concerned with staying under the eventual overall cost target.

Question 7:

> *Which elements of the BUILD program should be established by the Commission in a decision, and which should the BUILD program administrator have the flexibility to modify in implementation, with oversight by Commission staff?*

Response to Question 7:

Programs are most successful when the implementation team has the ability to adapt program requirements and processes in real time. As such, the Joint CCAs believe that the administrator should be given the responsibility to design and adapt the programs as needed to ensure success, as long as certain basic budget requirements and guidelines (such as ensuring that developments in CCA programs' service territories are provided a fair opportunity to access program funds) are met. As long as the administrator is a market-neutral party, such as the CEC, this approach should allow flexibility without undue risk of serious errors in the program.

Question 9:

> *Is the proposed mechanism for selecting a program administrator for the TECH program reasonable?*

Response to Question 9:

While the Joint CCAs generally view the proposed mechanism for selecting a program administrator for the TECH program reasonable, is essential that any party selected to administer the TECH program be entirely neutral and not be biased towards or against, or have any interest in, any LSE, developer, or technology type.

Question 11:

> *Comment on whether the Staff Proposal's analysis and recommendations for the TECH program's technology eligibility criteria, process for evaluating new technologies, guidelines and evaluation metrics, and criteria for scoring and selecting projects are reasonable.*

Response to Question 11:

The Joint CCAs applaud the Staff's recognition that the primary strategy for decarbonization should reflect electrification with appliances that do not have direct emissions. While renewable natural gas ("RNG") is a valuable resource, the limited supply of this resource should be best spent on areas where electrification is particularly difficult. Furthermore, as

California moves to electrify, any new natural gas infrastructure that would be required to serve RNG appliances in new build is likely to eventually represent stranded assets. Thus, the Joint CCAs support limiting eligibility of the BUILD program to all-electric build as the most appropriate for long-term decarbonization. Similarly, the Joint CCAs also support the consideration of non-GHG benefits, especially for DACs where air quality may generally be poor.

However, the Joint CCAs also recommend that the programs seize an opportunity to address the ability of electric appliances to engage in load shifting by adding a component for grid-dispatchable technologies in the technology eligibility criteria. The Staff Proposal recognizes that the carbon intensity of system electricity varies tremendously across the day, and that electrification can have significant grid impacts, but the Staff proposal fails to incorporate the communications capabilities into the technology evaluation criteria that would facilitate the ability of aggregators to deploy the kinds of load shifting products that could greatly increase GHG emissions reductions by moving load from high intensity hours into low carbon intensity hours. Looking forward to a future with increasing reliance on non-dispatchable generation, it will be increasingly important to be able to dispatch load to balance the grid. If these programs are to truly advance California's decarbonization, the programs should look beyond installing passive electrical devices to a generation of devices that are able to respond to grid needs.

These communications technologies are currently in their infancy, which is precisely why they should be supported, especially through the TECH program. Strategies such as the "quick start" program that seeks "vanguard strategies" should expressly look for call for proposals that would support smart-grid ready technologies, aggregation, and load dispatch. Such a call would provide a clear direction to market participants and support those entities already developing such technologies.

In addition, while the Joint CCAs agree with the general outline of the programs, they strongly suggest that the incentive budget for solar hot water heating be reallocated to other technologies. With the limited budgets of the BUILD and TECH programs, these funds would better be spent on technologies such as heat pumps for space and water heating, induction cooking, heat pump dryers, battery storage paired with solar PV, and grid interactivity features. Of the 250 participating homeowners in SCP's Advanced Energy Rebuild program, *none* have invested in a solar hot water system due to high costs and greater interest in (and flexibility of) solar PV and battery storage technologies. At a minimum, if the budget for solar hot water remains, it should be able to be reduced and/or reallocated in subsequent program years if there is lack of homeowner interest in solar hot water.

IV. CONCLUSION

The Joint CCAs thank the Commission for its consideration of these comments.

Dated: August 13, 2019

Respectfully submitted,

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BEFORE THE PUBLIC UTILITIES COMMISSION
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Order Instituting Rulemaking on the Commission's Own Motion to Conduct a Comprehensive Examination of Investor Owned Electric Utilities' Residential Rate Structures, the Transition to Time Varying and Dynamic Rates, and Other Statutory Obligations (U 39-E)	R.12-06-013 (Filed June 21, 2012)

REPLY COMMENTS OF THE
COMMUNITY CHOICE AGGREGATION PARTIES
ON THE PROPOSED DECISION ADDRESSING PHASE 4 ISSUES

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BEFORE THE PUBLIC UTILITIES COMMISSION
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Order Instituting Rulemaking on the Commission's Own Motion to Conduct a Comprehensive Examination of Investor Owned Electric Utilities' Residential Rate Structures, the Transition to Time Varying and Dynamic Rates, and Other Statutory Obligations (U 39-E)	))))))))	R.12-06-013 (Filed June 21, 2012)

REPLY COMMENTS OF THE
COMMUNITY CHOICE AGGREGATION PARTIES
ON THE PROPOSED DECISION ADDRESSING PHASE 4 ISSUES

Pursuant to Rule 14.3(d) of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission"), Marin Clean Energy, Sonoma Clean Power Authority and Silicon Valley Clean Energy Authority (collectively "CCA Parties") hereby file this reply to the opening comments of Pacific Gas and Electric Company ("PG&E") on the *Proposed Decision of ALJ Park Addressing Phase 4 Issues* ("Proposed Decision").[1] The CCA Parties did not file opening comments on the Proposed Decision since the CCA Parties did not identify any errors in the Proposed Decision.

I. REPLY COMMENTS

A. PG&E Fails To Identify Any Errors In The Proposed Decision

PG&E's comments fail to identify any errors in the Proposed Decision, as required by Rule 14.3(c). Instead, as further discussed below, PG&E focuses on redefining the word "benefit" and in doing so fails to properly apply the Commission's clear requirements and

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[1] By operation of Rule 1.15, these reply comments are timely filed today, since the fifth day following PG&E's filing of its opening comments was a Saturday.

standards with respect to cost-shifting. Because PG&E has failed to identify any errors in the Proposed Decision, its comments should "be accorded no weight."[2]

B. PG&E Has A Truncated View Of The Controlling Standard

In its comments, PG&E seeks to selectively excerpt a portion of the Proposed Decision pertaining to PG&E's ***bill protection costs*** and apply this language to PG&E's ***online rate comparison costs***.[3] By selectively applying this language, PG&E does injustice to the controlling standard, fails to rebut the clear findings and conclusions set forth in the Proposed Decision pertaining to PG&E's online rate comparison costs, disregards the differing factual circumstances between the two cost categories, and improperly seeks to reform its insufficient evidentiary showing.

The Proposed Decision makes clear that mere assertions that costs "will benefit CCA customers in the future," as alleged by PG&E, are insufficient to carry PG&E's burden of proof with respect to its request.[4] Instead, PG&E's request must satisfy a two-part test: (1) there should be no cost-shifting between bundled and unbundled customers,[5] and (2) costs should be allocated to those customers on whose behalf the costs were incurred.[6] The Proposed Decision makes clear that "[i]t is undisputed that the rate comparison tool functionality was not available to or functional for CCA customers during this time period [and that] PG&E also did not provide the online rate comparison tool to customers as part of the opt-in TOU pilot."[7] Importantly,

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[2] *See* Rule 14.3(c).
[3] *See* PG&E Opening Comments at 2.
[4] *See* Proposed Decision at 9, note 18 (citing numerous Commission decisions that require facts showing more than "indirect societal benefits").
[5] *See* Proposed Decision at 8-9, note 14.
[6] *See* Proposed Decision at 9, note 15.
[7] Proposed Decision at 9.

PG&E does not dispute these facts, or claim error. Instead, PG&E seeks to excerpt a different standard – a standard applied to a different cost category.

As noted by the CCA parties in their briefs, the CCA Parties generally support recovery of costs through distribution rates when CCA customers receive a share of benefits that is ***fair and equitable*** compared to benefits received by bundled customers.[8] As pointed out in the Proposed Decision, "the Commission previously determined that the purpose of bill protection for the opt-in pilot was as an incentive for recruitment and retention. . ."[9] In light of this distinguishing fact, the CCA Parties do not dispute the Proposed Decision's conclusion that the ***bill protection*** costs are properly collected from all customers through distribution rates, since "since CCA customers are participating in the default pilot and will also be participating in the full transition to default TOU."[10]

The same facts and conclusions do not apply to ***online rate comparison*** costs. To the contrary, it would be inconsistent with cost causation principles to allocate the costs associated with the online rate comparison tool for 2015-2016 to CCA customers since "the rate comparison tool functionality was not available to or functional for CCA customers during this time period."[11]

In opening comments, PG&E argues that it did present evidence that the costs associated with its online rate comparison tool recorded during the 2015-2016 period were incurred on behalf of CCA customers.[12] PG&E suggests that the evidence it presented was an explanation by PG&E's witness regarding how the rate comparison tool functions (as the CCA Parties

8 *See* CCA Parties Opening Brief at 8-9; *see also* CCA Parties Reply Brief at 6-7.
9 *See* Proposed Decision at 11.
10 *See id.*
11 *See* Proposed Decision at 9.
12 *See* PG&E Opening Comments at 1.

understand) *today*.[13] However, the only costs that are at issue in this proceeding are those costs recorded in 2015-2016, and the statement cited in PG&E's opening comments does not demonstrate that the 2015-2016 costs associated with its online rate comparison tool "were incurred on behalf of CCA customers" as required by the Proposed Decision.[14] For their part, the CCA Parties supported the fact that, prior to 2017, "PG&E did not provide ***any*** analysis for CCA customers (even a proxy analysis)."[15] Therefore, the CCA Parties demonstrated, and the Proposed Decision correctly concludes, that the rate comparison tool costs for the 2015-2016 time period provided specific benefits that were not available to CCA customers. Accordingly, since PG&E's rate comparison tool did not provide a fair and equitable share of benefits to all customers in 2015-2016, the Proposed Decision appropriately concludes costs from this time period "associated with the online rate comparison should be allocated to [PG&E's] generation rates."[16]

One final point bears attention. In its opening comments, PG&E rightly acknowledges that "it has the burden to present sufficient evidence in support of its position" and "that the Administrative Law Judge and Commission have the discretion to evaluate the sufficiency of that evidence."[17] Exercising this discretion, the Proposed Decision clearly finds that "PG&E failed to present evidence that any costs associated with its online rate comparison tool recorded in the RRRMA during the 2015-2016 period were incurred on behalf of CCA customers."[18] As noted above, PG&E does not assert in its opening comment that this finding is erroneous. As

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13 *See* PG&E Opening Comments at 2.
14 *See* Proposed Decision at 9.
15 *See* CCA Parties Opening Brief at 9.
16 Proposed Decision at 9-10.
17 PG&E Opening Comments at 2. *See also* Proposed Decision at 8, note 13 (citing CCA Parties Opening Brief at 4-5) ("As noted by the CCA Parties, PG&E bears the burden of proof with respect to its request.").
18 Proposed Decision at 19; Finding of Fact 5.

such, it would be improper for PG&E to now be allowed, after extensive litigation and briefing, to reform its showing. PG&E's opening comments should be accorded no weight.

C. PG&E Statements Affirm The Proposed Decision's Findings

In acknowledging that it will implement the Proposed Decision as-is, PG&E states that it will "identify 2015- 2016 costs associated with the online rate comparison tool functionalities that were ***unavailable to CCA customers*** during the 2015- 2016 period…"[19] Moreover, PG&E makes other statements underscoring that any benefit from the rate comparison tool will be an alleged, undefined "future" benefit.[20] These statements affirm the Proposed Decision's conclusion that PG&E has failed to provide sufficient details and showings to carry its burden.

II. CONCLUSION

The CCA Parties thank the Commission for its consideration of the matters set forth in this reply to PG&E's opening comments on the Proposed Decision.

August 26, 2019

Respectfully Submitted,

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[19] PG&E Opening Comments at 3; emphasis added.

[20] *See, e.g.,* PG&E Opening Comments at 2.

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

OPENING COMMENTS OF MARIN CLEAN ENERGY AND THE ASSOCIATION OF BAY AREA GOVERNMENTS ON BEHALF OF THE SAN FRANCISCO BAY AREA REGIONAL ENERGY NETWORK ON THE PROPOSED DECISION ADOPTING ENERGY EFFICIENCY GOALS FOR 2020 – 2030

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August 5, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
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Marin Clean Energy ("MCE") and the Association of Bay Area Governments ("ABAG"), on behalf of the San Francisco Bay Area Regional Energy Network ("BayREN") submit the following Opening Comments in response to the *Proposed Decision Adopting Energy Efficiency Goals for 2020-2030* ("Proposed Decision"), filed on July 15, 2019. As two non-investor-owned utility ("IOU") energy-efficiency ("EE") program administrators ("PAs"), MCE and BayREN highlight some challenges with the current and proposed rules and procedures surrounding the determination of EE potential and goals for non-IOU PAs. First and foremost, MCE and BayREN encourage the Commission and Navigant to implement a process to disaggregate energy savings potential and goals for Community Choice Aggregators ("CCAs") and Regional Energy Networks ("RENs") in the EE Potential and Goals Study ("P&G Study") so that CCA and REN customers receive the same value from the study as bundled customers.

Additionally, MCE and BayREN recommend a couple changes to the guidance in the Proposed Decision for the upcoming Annual Budget Advice Letter ("ABAL") submissions. First, MCE and BayREN propose two interim solutions for addressing the determination of energy savings goals for non-IOU PAs until the point at which the P&G Study is updated. Second, MCE and BayREN request the Commission to determine a more specific timeline for incorporating pending updates to the Avoided Cost Calculator ("ACC") proposed by draft Resolution E-5014 into the ABAL submission.

I. COMMENTS

A. The Commission Should Establish a Timeline to Develop a Methodology for Parsing Out Savings for CCAs and RENs under the P&G Study

The Commission convened two workshops on the development of the 2019 Potential and Goals Study on January 11 and March 21, 2019. During the first workshop, the concept of disaggregation of energy savings goals for CCAs and RENs under the P&G Study was introduced. During the second workshop in March, Navigant Consulting, Inc. ("Navigant") announced that the disaggregation of CCA and REN energy savings goals will be included in a "Volume 2 Technical Analysis," which is postponed until "After May 1, 2019 (exact timeline TBD)."[1]

MCE, in a joint filing with the City of Lancaster ("Lancaster"), noted the importance of addressing the issue of disaggregation for CCAs and RENs and noted specific concerns with the top-down disaggregation approach proposed by Navigant.[2] Additionally, BayREN and Tri-County Regional Energy Network (3C-REN) filed joint comments addressing similar concerns regarding Navigant's approach and timeline. Unfortunately, the final P&G study does not address any of the

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[1] Powerpoint presentation from *2019 Potential and Goals Study Workshop*, March 21, 2019, slide 6

[2] Comments of Marin Clean Energy and the City of Lancaster in response to the Administrative Law Judge's Ruling Inviting Comments on Draft Potential and Goals Study, filed on May 1, 2019.

issues or concerns brought forward by MCE, Lancaster, BayREN and 3C-REN, and the study remains unspecific about developing energy savings potential and goals for CCAs and RENs.[3]

The Commission should not accept any further delay in determining the EE potential and goals for customers in CCA and REN territory and should direct Navigant to develop a methodology for parsing out savings for CCAs and RENs, with specific deadlines and milestones. CCAs and RENs would appreciate the opportunity to closely collaborate with Navigant in the development of such a methodology.

B. Non-IOU PAs Should Be Allowed to Update Their Energy Savings Goals Forecast on a Biennial Basis via the Annual Budget Advice Letter Submission Process

MCE and BayREN appreciate the Commission's clarification in the Proposed Decision that, "for each year that non-IOU PAs request EE funding authorization via an ABAL, they shall meet or exceed the annual savings forecasts presented in their true-up tables as submitted in their PY 2019 ABAL"[4] instead of having to meet or exceed the energy savings targets included in the Business Plans as established in D.18-05-041.[5]

However, MCE and BayREN would also like to request the ability to update their energy savings forecast on a biennial basis in alignment with the process for the IOUs. As noted above, the PD determines that non-IOU PAs are held to the annual energy savings goals established in the PY2019 true-up tables which determined annual energy savings forecasts from 2019 through

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[3] In Appendix I Response to Comments in the final P&G Study, Navigant states that disaggregation of potential to CCAs (as well as RENs and DACs) will happen "at a later date" and on p.11 of the final P&G study they state that research regarding savings within RENs/ CCAs will be conducted "later in 2019".

[4] Proposed Decision at 27

[5] D.18-05-041 at 134.

2025. Under the proposed rules, non-IOU PAs would not have the opportunity to update their annual energy savings goals for the entire business plan period (i.e., through 2025) while the IOUs receive updated energy savings goals through the P&G Study on a biennial basis. Additionally, the PY2019 true-up tables energy savings forecasts include market effects adjustments of 5 percent, which impacts both the net savings and TRC forecasts. Therefore, PD's guidance to exclude market effects adjustment from program administrators future ABALs will no longer align with the forecasts filed in the PY2019 ABAL. For the reasons aforementioned, MCE and BayREN respectfully request the Commission allow non-IOU PAs to update their annual energy savings forecast via the submission of an updated true-up table with their submissions of the ABAL on a biennial basis.

Such request is in alignment with the IOU's update of their energy savings goals via the P&G study. Further, the requirement for PAs to present their draft ABALs to CAEECC is already included in the ABAL process per D. 18-05-041. Therefore, by submitting the updated energy savings forecast via the ABAL, stakeholders will have the opportunity to review and provide comments on the proposed updates, and any potential concerns could be addressed prior to the ABAL submission deadline in September. Once the P&G study includes a disaggregation of EE potential and goals for CCAs and RENs, this provision would be revoked and energy savings goals for non-IOUs would be established via the P&G study for all EE PAs.

C. The Commission Should Make Updates to the ACC According to the Bus Stop Schedule under the EE Business Plans[6] and if Delays Occur, those Updates Should Be Included in the Following Year's ABAL Submissions

[6] The bus stop schedule under the EE rolling portfolio was adopted in D.15-10-028.

MCE and BayREN appreciate the Commission's determination in the Proposed Decision that EE PAs may use the Avoided Cost Calculator approved by the Commission as of July 12, 2019 for their PY 2020 ABAL submissions.[7] However, the language in the Proposed Decision is unspecific in regards to when and in which format EE PAs are required to incorporate the pending updates to the ACC proposed by draft Resolution E-5014 into the ABAL submission process. MCE and BayREN are concerned that last minute changes to the ACC occurring shortly before the ABALs' due date is disruptive to the required stakeholder review process under the California Energy Efficiency Coordinating Committee ("CAEECC"). EE PAs are required to submit draft ABALs to CAEECC by the end of July of each year to minimize protest and facilitate stakeholder feedback before the final ABAL submission in the beginning of September. If updates to the ACC are made in late July and PAs are given the option to use either version of the ACC for their ABAL submissions, the consistent review of the PA's ABALs through the CAEECC stakeholder review process is in jeopardy

In the spirit of clearly delineating ABAL filing requirements, MCE and BayREN recommend that the Commission should make updates to the ACC according to the Bus Stop Schedule under the EE Business Plans and if delays occur, those updates should be included in the following year's ABAL submissions. For the 2020 ABAL submission, this means that EE PAs will use the ACC approved by the Commission as of July 12, 2019 for the PY 2020 ABAL submission on September 3, 2019 as specified in the Proposed Decision. The Commission should also clarify that any updates made to the ACC after July 12, 2019 will be incorporated into the 2021 ABAL submission to give PAs sufficient time to make any necessary adjustments to maintain a cost-effective portfolio.

[7] Proposed Decision at 27.

III. CONCLUSION

MCE and BayREN thank Commissioner Randolph and Administrative Law Judges Fitch and Kao for their consideration of these comments. MCE and BayREN look forward to continuing to work with the Commission, Navigant, and other stakeholders in order to ensure that CCA and REN programs and their customers are given appropriate and careful consideration in the development of EE goals.

August 5, 2019

Respectfully Submitted,

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August 12, 2019

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Marin Clean Energy ("MCE") and the Association of Bay Area Governments ("ABAG"), on behalf of the San Francisco Bay Area Regional Energy Network ("BayREN") submit the following reply comments in response to opening comments to the *Proposed Decision Adopting Energy Efficiency Goals for 2020-2030* ("Proposed Decision"), filed on July 15, 2019.

I. Summary

MCE and BayREN jointly filed comment on the PD and asked the Commission to allow Non-Investor Owned Utilities (IOU) Program Administrators (PAs) to update their energy savings goals forecasts on a biennial basis via the Annual Budget Advice Letter Submission (ABAL) Process. Additionally, MCE and BayREN urged the Commission to establish a timeline to develop a methodology for parsing out savings for Community Choice Aggregators (CCAs) and Regional Energy Networks (RENs) under the Potential and Goal (P&G) study. In these reply comments, MCE and BayREN:

- Support SoCalREN's request that the CPUC amend the PD to require RENs and CCAs to meet or exceed the annual savings forecasts presented in their true-up tables as submitted in their preceding year ABAL.
- Support Southern California Edison's (SCE) recommendation that the Commission align future P&G Studies with the avoided cost calculator update schedules as defined in D.19-05-019, and to specifically reevaluate the rolling portfolio's "bus stop" schedules.

II. Discussion

A. MCE and BayREN support SoCalREN's request to allow non-IOU PAs to update their energy goals annually in the preceding year's ABALs

BayREN and MCE agree with SoCalREN's assessment that using the energy savings forecasts provided in the program year (PY) ABAL of 2019 does not accurately reflect what non-IOU PAs should achieve over the rolling portfolio.[1] These "true-up" tables were based on the best available information at the time and included assumptions about program activities and interventions that naturally evolve and change overtime. The Commission should allow the non-IOU PAs to update their energy goals annually or biennially to ensure the energy savings targets reflect accurate and updated forecasts and stay in sync with the P&G update schedule.

B. The Commission should align future Potential and Goals studies with the avoided costs calculator update schedule and reevaluate the rolling portfolio bus stop schedules

MCE and BayREN agree with SCE that "there has been a structural rolling portfolio lag time between the Potential and Goals Study the Integrated Distributed Energy Resources (IDER)

[1] SoCalREN Comments, Aug 5, 2019, p. 1

proceeding's Avoided Cost Calculator updates."[2] The time lag impacts cost-effectiveness analysis and puts an undue burden on PAs to submit updates according to the bus stop schedules. MCE and BayREN support SCE's recommendation to reevaluate the rolling portfolio's bus stop schedules to ensure key updates occur at the appropriate time and align with other interrelated proceedings, including the California Energy Commission's demand forecasting and the updates to the Database of Energy Efficiency Resources (DEER) Resolution.

III. Conclusion

MCE and BayREN thank Commissioner Randolph and Administrative Law Judges Fitch and Kao for their consideration of these reply comments. MCE and BayREN look forward to continuing to work with the Commission, Navigant, and other stakeholders to ensure that CCA and REN programs are given appropriate and careful consideration in the development of EE goals.

August 12, 2019

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[2] SCE Comments, Aug 5, 2019, p.4