DECEMBER FILINGS

California ISO

Submit comment on November 18, 2021 stakeholder meeting

2021-2022 Transmission planning process

1. Please provide your organization's comments on the Preliminary Policy Assessment, as described in the second portion of the presentation:

California Community Choice Association (CalCCA) supports the California Independent System Operator's (CAISO) identification of policy driven projects under the base portfolio and requests the CAISO also consider projects identified in the sensitivity-1 portfolio based on the 38 MMT green-house gas (GHG) target.

CalCCA supports the CAISO's identification of policy driven projects under the base portfolio. Additionally, in the previous Transmission Planning Process (TPP) workshop, the CAISO indicated that it intends to consider additional upgrades to reflect the increase in resource procurement and provide flexibility for resources not currently in the base portfolio.[1] CalCCA supports the CAISO's intention to "get ahead of" the large number of resources expected to be included in future portfolios by considering additional upgrades beyond those identified using the base portfolio. Identifying additional upgrades now in anticipation of increased resource build could provide the necessary signals to resources as to where to site new resource build necessary to meet the required forty percent reduction in statewide GHG emissions by December 31, 2030, the Renewable Portfolio Standard of 60 percent by December 31, 2030, and the goal of a zero-carbon electric system by 2045.[2]

To do this, the CAISO should consider projects identified in the sensitivity-1 portfolio based on 38 million metric ton (MMT) green-house gas (GHG) targets. As outlined in CalCCA's comments in the Integrated Resource Planning (IRP) proceeding, CalCCA supports the base case of 38 MMT Core for the preferred system plan and for consideration in the TPP.[3] CalCCA appreciates the CAISO including the sensitivity-1 scenario as a sensitivity in this year's TPP, and recommends the CAISO consider the sensitivity-1 scenario when considering additional upgrades beyond those identified in the base portfolio.

2. Provide your organization's comments on the Preliminary Economic Assessment, as described in the third portion of the presentation:

No comments at this time.

3. Provide your organization's comments on Reliability Projects less than $50 million, as described in the fourth portion of the presentation:

No comments at this time.

4. Provide your organization's comments on the PG&E Area High Voltage Assessment (update), as described in the fifth portion of the presentation:

No comments at this time.

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1 CAISO Day 2 Presentation on the 2021-2022 Transmission Planning Process, Sept. 27-28, 2021 at 12.

2 Health and Safety Code § 38566, Public Utilities Code § 399.15(a), Public Utilities Code § 454.53(a).

3 California Community Choice Association's Comments on Administrative Law Judge's Ruling Seeking Comments on Proposed Preferred System Plan, R.20-05-003, Sept. 27, 2021.

5. Provide your organization's comments on the 20 Year Transmission Outlook (update), as described in the final portion of the presentation:

CalCCA supports the CAISO's efforts in developing the 20-year transmission outlook based on the Senate Bill (SB) 100 starting point scenario.

CalCCA reiterates its appreciation from previous comments on the CAISO's efforts to develop the 20-year Transmission Outlook. [4] Forward planning with a long enough lead time will be critical in ensuring the state is prepared to meet SB 100 goals that require renewable energy and zero-carbon resources to supply 100 percent of electric retail sales to end-use customers by 2045.

6. Provide additional comments (if any) on the November 18, 2021 stakeholder meeting:

CalCCA supports the CAISO's identifying load impacts of potential Public Safety Power Shutoff (PSPS) events.

CalCCA commends the CAISO for its look at wildfire impacts in the TPP. As wildfires become increasingly prevalent in California, this assessment will provide useful information regarding grid resiliency. CalCCA requests clarity on how the CAISO plans to utilize the results of the impact assessment to reduce future PSPS events or wildfire impacts.

The CAISO Should Consider How to Incorporate Policy Driven Assessments in Local Areas in the Next TPP Cycle.

CalCCA understands that the CAISO assesses proposed transmission upgrades and alternatives for reducing reliance on gas-fired resources in local capacity areas in its economic-driven study phase. In the 2020-2021 TPP cycle, the CAISO assessed the economic value of reducing the need for gas-fired generation through transmission and other alternatives by applying the differential between the local and system capacity prices.[5] As the fleet of resources evolves, the potential for a local constraint to become binding will increase. Analysis of the divergence of system and local prices will be important to inform the impacts and to determine whether transmission should be built to resolve local area resource constraints. In addition to these economic assessments, a policy-driven assessment should be performed to identify transmission upgrades or alternatives that facilitate retirements for fossil fuel plants on a timeline that maintains reliability in local areas and makes progress on state environmental requirements including minimizing air emissions in disadvantaged communities.[6]

In the next TPP cycle, the CAISO should incorporate a policy-driven assessment into its evaluation of transmission upgrades or alternatives needed to address local needs. As the state works towards achieving a zero-carbon electric system by 2045, more renewable resources and storage will necessarily come online creating opportunities for existing fossil fuel plants to retire. However, if an existing fossil fuel plant is in a locally constrained area, the resource retirement will not occur until the transmission constraint is eliminated or enough carbon-free resources are built in the local area to fulfill the local need. This could result in delays in meeting environmental standards if transmission capacity or other alternatives are not built to address the local need. The CAISO should consider transmission upgrades and potential alternatives to alleviate local area transmission constraints that would allow fossil fuel plants to retire to meet the State's GHG mandate reliably.

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[4] CalCCA Comments on the July 27, 2021 TPP Stakeholder Call and CalCCA Comments on the Sept. 28, 2021 TPP Stakeholder Call.

[5] 2020-2021 Transmission Plan at 250.

[6] See Public Utilities Code § 454.52(a)(1)(h).

FILED
12/06/21
04:59 PM

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration of California Renewables Portfolio Standard Program.	R.11-05-005 **(Not Consolidated)**
Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program.	R.15-02-020 **(Not Consolidated)**
Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program.	R.18-07-003 **(Not Consolidated)**

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON THE PROPOSED DECISION MODIFYING THE RENEWABLE MARKET ADJUSTING TARIFF PROGRAM AND DIRECTING IMPLEMENTATION

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December 6, 2021

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BEFORE THE PUBLIC UTILITIES COMMISSION
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CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON THE PROPOSED DECISION MODIFYING THE RENEWABLE MARKET ADJUSTING TARIFF PROGRAM AND DIRECTING IMPLEMENTATION

The California Community Choice Association[1] (CalCCA) submits these reply comments pursuant to Rule 14.3(d) of the California Public Utilities Commission (Commission) Rules of Practice and Procedure on the proposed *Decision Modifying the Renewable Market Adjusting Tariff Program and Directing Implementation* (PD), issued on November 10, 2021.

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[1] California Community Choice Association represents the interests of 23 community choice electricity providers in California: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

I. IF THE COMMISSION APPROVES THE IOUS' REQUEST FOR REMAT COST RECOVERY THROUGH THE PPPC, IT MUST ENSURE EQUITABLE ALLOCATION OF THE RPS AND RA ATTRIBUTES TO BOTH BUNDLED AND UNBUNDLED CUSTOMERS

CalCCA submits these limited reply comments in response to the Joint Opening Comments of Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (SCE), and the Opening Comments of San Diego Gas & Electric Company (SDG&E) (PG&E, SCE and SDG&E are collectively referred to herein as the "IOUs"). As set forth in previous CalCCA comments on the Renewable Market Adjusting Tariff (ReMAT) cost allocation issue, of paramount concern is that the cost allocation among bundled and unbundled customers equitably distribute the ReMAT contracts' Renewable Portfolio Standard (RPS) and Resource Adequacy (RA) benefits.[2] Under the current methodology, unbundled customers receive the value or attributes through the Power Charge Indifference Adjustment (PCIA) calculation. The IOUs' Opening Comments (as well as the Petition for Modification (PFM) submitted by PG&E and SCE in February, 2021) insist that the Commission revise the cost responsibility for the ReMAT contracts, stating that the Proposed Decision should "adopt broad cost allocation for ReMAT."[3] The PG&E and SCE Joint Opening Comments do refer to the Joint IOU PFM as providing the facts needed to resolve the cost allocation issue, but the Joint Opening Comments do not elaborate on the methodology to do so.[4]

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[2] *See Response of California Community Choice Association to Joint Petition for Modification of Decision 13-05-034 by Pacific Gas and Electric Company (U 39 E) and Southern California Edison Company (U 338 E),* Rulemaking (R.) 11-05-005 (Mar. 15, 2021); *see also California Community Choice Association's Comments on the Proposed Decision Modifying the Renewable Market Adjusting Tariff Program and Directing Implementation,* R.11-05-005, R.15.-02-020, R.18-07-003 (Nov. 30, 2021) (Joint IOU PFM).

[3] PG&E and SCE Joint Opening Comments at 5; *see Joint Petition for Modification of Decision 13-05-034 by Pacific Gas and Electric Company (U 39 E) and Southern California Edison Company (U 338 E),* R.11-05-005 (Feb. 11, 2021).

[4] PG&E and SCE Joint Opening Comments at 5.

The current PCIA methodology adequately addresses the cost allocation issue. However, if the Commission does revise the methodology, it must ensure that community choice aggregator (CCA) customers paying for the program receive equal benefits. If the Commission determines that the ReMAT contract costs should be recovered through the PPPC, the Commission should order, as the IOUs have previously proposed,[5] that only ***net*** ReMAT costs are recovered. Revenues associated with all attributes of value – energy, Renewable Energy Credits, and RA – should be netted against the ReMAT costs. Energy would be sold into the CAISO market, and the resulting revenues would offset the ReMAT costs. Bundled customers would pay for the RPS and RA attributes at the market price benchmark, allowing the value of those attributes to benefit unbundled customers. Above-market costs would then be borne equitably among both bundled and unbundled customers, preventing cost-shifting.

II. CONCLUSION

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

Respectfully submitted,

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

December 6, 2021

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[5] *See* Joint IOU PFM at 11-12 ([t]he ReMAT [non-bypassable charge (NBC)] would be consistent with . . . [implementation of] the BioMAT NBC whereby utility will retain the RA or RPS attributes for the benefit of bundled service customers and the bundled service customers will pay for the RA or RPS attributes at the Commission's calculated annual market price benchmark. The ReMAT NBC would be collected through the IOU's PPPC").

Comments on Central procurement entity implementation - issue paper and straw proposal

Export

Central procurement entity implementation

Comment period Nov 23, 08:00 am - Dec 08, 05:00 pm

Submitting organizations California Community Choice Association, California Department of Water Resources, Metropolitan Water District, Middle River Power, LLC, Pacific Gas & Electric, Southern California Edison

VIEW BY: **Organization** **Question**

California Community Choice A...
California Department of Water...
Metropolitan Water District
Middle River Power, LLC
Pacific Gas & Electric
Southern California Edison

California Community Choice Association

SUBMITTED 12/06/2021, 03:04 PM

Contact
Shawn-Dai Linderman (shawndai@cal-cca.org)

1. **Please provide a summary of your organization's comments on the issue paper and straw proposal.**

California Community Choice Association (CalCCA) appreciates the California Independent System Operator's (CAISO) timely initiation of this stakeholder process to implement a central procurement entity (CPE) structure for local resource adequacy (RA). This stakeholder process is necessary to ensure CAISO systems and processes can accommodate CPE showings beginning in RA year 2023. The CAISO's proposal focuses on tariff, business process, and software changes needed to accommodate the existing CPE structure as outlined in the California Public Utilities Commission's (Commission) Decision (D.) 20-06-002, recognizing that Rulemaking (R.) 21-10-002 is contemplating additional modifications to the existing structure. CalCCA generally supports the CAISO's straw proposal for implementing a CPE structure in the CAISO's RA processes. CalCCA's comments focus on ongoing progress that has been made thus far in central procurement for 2023 and 2024 that has highlighted areas for improvement to the current structure. These improvements are likely best addressed in R.21-10-002, however, CalCCA raises them in this forum as the effectiveness of the hybrid CPE framework has impacts on reliability, LSE procurement of system and flexible RA, and the CAISO's role as the backstop authority.

D.20-06-002 adopted a hybrid central buyer framework for local RA in Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (SCE) service areas beginning with the 2023 RA compliance year. Under this framework, load-serving entities (LSEs) in PG&E and SCE territories will no longer receive local RA allocations. Instead, the CPE will be required to meet the local RA obligations through its own procurement using all-source solicitations or through "shown" resources offered by LSEs who retain the system and flexible attributes of resources they have procured but use the local attribute to reduce the CPE's overall procurement requirement. The CPE can also defer procurement to the CAISO's backstop mechanisms if procurement costs are deemed unreasonably high.

As the CAISO notes, the Commission's initial scoping memo in R.21-10-002 indicated the Commission may consider modifications to the CPE hybrid procurement structure, process, and timeline.[1] While the CAISO will not be discussing how to modify the hybrid resource framework in this initiative and directs parties to raise policy concerns related to this framework in the Commission's proceeding, the effectiveness of the CPE framework will impact both LSE's ability to procure to meet their system and flexible RA requirements and the CAISO's need to rely on the Capacity Procurement Mechanism (CPM).

PG&E filed a Supplemental CPE Annual Compliance Report filed on November 19, 2021.[2] The supplemental advice letter shows aggregate CPE procurement for the 2023 and 2024 compliance years. Total CPE procurement for 2023 is short of the 100 percent local RA requirement by roughly 4,000 to over 6,000 megawatts (MW) in some months. Total CPE procurement for 2024 is over 600 MW short of the 50 percent local RA requirement. It is not clear in the advice letter if the CPE will attempt to do more procurement to meet the local obligation or defer procurement to the CAISO's CPM authority.

This raises significant uncertainty for LSEs who need to procure to meet their system and flexible obligations and are left unclear of the amount of system and flexible RA credits they will receive from procurement done by the CPE. This also raises questions around the magnitude of CAISO's role as the backstop authority. If a CPE defers to the CAISO CPM authority, without understanding why the CPE deferred to CAISO's backstop authority, it is unclear whether resources will be available for the CAISO to CPM and if the CAISO backstop mechanisms will be able to procure and allocate to fill the need under a relatively short timeframe. For example, if the CPE deferred to the CAISO backstop because bids into the CPE's solicitation were unreasonably high, the CAISO may be able to CPM local resources to meet the requirement. However, if the CPE deferred to the CAISO backstop because not enough resources were offered into the solicitation, the CAISO may not be able to CPM local resources to meet the requirement because resources are being used to meet other obligations.

LSEs and the CAISO would benefit from additional transparency in advance about the CPE's intent to defer procurement to the CAISO as the backstop authority and the reason for deferment, especially if the CPE forgoes procurement of a significant portion of the local obligation. Greater transparency around CPE procurement efforts would provide LSEs, the CAISO, and other stakeholders the ability to assess and understand how the current CPE structure is functioning and if the current structure will result in sufficient procurement of local resources to maintain system reliability and whether it will place significant pressure on CAISO backstop mechanisms with relatively little time for such procurement and allocation to occur.

[1] Supplemental: Pacific Gas and Electric Company ("PG&E") Central Procurement Entity ("CPE") Annual Compliance Report, Nov 19, 2021: https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_6386-E-A.pdf

[2] Order Instituting Rulemaking, R.21-10-002, October 11, 2021, at 5: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M414/K681/414681705.PDF

2. **Please provide comments on the system and local obligation for CPE and LSEs with load in multiple TAC Areas.**

   CalCCA has no additional comments at this time.

3. **Please provide comments on the allocation of system and flexible attributes of Local RA Resources.**

   CalCCA has no additional comments at this time.

4. **Please provide comments on the clarification of CPM Process and Cost Allocations.**

   CalCCA has no additional comments at this time.

5. **Please provide comments on the RAAIM settlment process enhancements.**

   CalCCA has no additional comments at this time.

6. **Please provide comments on the EIM Govering Body classification.**

   CalCCA supports the EIM Governing Body classification of this initiative.

7. **Please provide any additional input not included above related to the issue paper and straw proposal.**

   CalCCA has no additional comments at this time.

California Department of Water Resources

SUBMITTED 12/06/2021, 09:10 AM

Contact
Mohan Niroula (mohan.niroula@water.ca.gov)

1. **Please provide a summary of your organization's comments on the issue paper and straw proposal.**

   CDWR supports the following aspects in the CAISO proposal:

   a. Confirmation that non-CPUC jurisdictional entities are not required to procure local RA resources through the central procurement entity (CPE) procurement process applicable to CPUC jurisdictional entities.
   b. Continue allocating local RA obligation to non-CPUC jurisdictional entities with a voluntary option to shift all or a part of local RA obligation to a CPE formed by non-CPUC jurisdictional LSEs.
   c. An LSE's (or a CPE's) local RA obligation in a TAC area will be limited to the LSE's (or the CPE's) applicable planning reserve margin and the demand in that TAC area.

d. Maintain the current one year ahead annual RA showing process with respect to the CPUC's multi-year RA procurement and showings.
e. Modify the tariff to allow a CPE to be assigned a local RA obligation, CPM cost, and RA credits.

2. **Please provide comments on the system and local obligation for CPE and LSEs with load in multiple TAC Areas.**

CDWR supports CAISO's proposal to cap the local RA obligations for an LSE with load in multiple TAC areas to their demand and planning reserve margin in each specific TAC area and not on the LSE's overall system RA obligations. This will eliminate an unfair burden on LSEs with load in multiple TAC areas potentially having a higher local CPM cost allocation compared to an LSE with load in a single TAC area.

However, it should be made clear that this proposal applies to both the annual and the monthly RA showings.

CAISO proposes that any CPE will be required to submit annual and monthly plans. Will the LSEs under a CPE be exempt from submitting annual and monthly plans (because the CPE for the LSE will submit monthly and annual plans)? Will both the LSE and the CPE be required to submit annual and monthly plans in case of partial shifting of LSE local RA obligation to a CPE?

3. **Please provide comments on the allocation of system and flexible attributes of Local RA Resources.**

CDWR agrees with the bundling of capacity and the need to make necessary arrangements for RA credit assignment due to the bundling of the system and flexible attributes.

4. **Please provide comments on the clarification of CPM Process and Cost Allocations.**

CDWR agrees that: a) a CPE should be allocated CPM costs for applicable individual and/or collective deficiency. b) a CPE should also be able to receive RA credits after the cost allocation.

5. **Please provide comments on the RAAIM settlment process enhancements.**

CDWR does not object to the CAISO proposal to modify the current rule that unavailability charge assessed more than the monthly cap will rollover to fund allocations in future months. CAISO proposes that allocation be based on the trading month activities using the current formula for year-end allocations.

6. **Please provide comments on the EIM Govering Body classification.**

No comments.

7. **Please provide any additional input not included above related to the issue paper and straw proposal.**

No further comments.

Attachments

- StakeholderCommentTemplate-CPE implementation-CDWR-12062021Final-approved.docx

Metropolitan Water District

SUBMITTED 12/06/2021, 04:22 PM

Contact
John Michael Jontry (jjontry@mwdh2o.com)

1. **Please provide a summary of your organization's comments on the issue paper and straw proposal.**

Comments on the RAAIM settlements enhancement proposal

2. **Please provide comments on the system and local obligation for CPE and LSEs with load in multiple TAC Areas.**

3. **Please provide comments on the allocation of system and flexible attributes of Local RA Resources.**

4. **Please provide comments on the clarification of CPM Process and Cost Allocations.**

5. **Please provide comments on the RAAIM settlment process enhancements.**

   The Metropolitan Water District of Southern California (MWD) has reviewed the straw proposal and notes with concern the following language on page 16 –

   "Furthermore, the CAISO proposes to exclude market participants that have Transmission Ownership Rights (TOR) and Existing Transmission Contracts from the metered demand calculation. Existing Transmission Contracts entitle the SC to serve their Demand (Load + Export) from their supply resource (Generation + Import) using their transmission rights, and thus are not exposed to congestion charges. These schedules need to be self-scheduled in the market and do not require the market to dispatch RA generation to meet their load. This portion of load should not receive an allocation of excess funds because they are not dependent on their procured RA capacity to bid into the market to cover their load."

   MWD notes that as a market participant with TORs, we have the following concerns:

   1. MWD's generation that participates in the CAISO market will still be subject to RAAIM penalties, but MWD will no longer be eligible for excess RAIMM penalties, and
   2. The straw proposal does not reduce the RA showing requirements of entities that use TOR's to meet their RA needs.

   This reduction of benefits with no concomitant reduction in penalties or obligations, on the face of it, does not appear fair. We would request that the CAISO clarify their reasoning for this change or consider a different approach.

6. **Please provide comments on the EIM Govering Body classification.**

7. **Please provide any additional input not included above related to the issue paper and straw proposal.**

Middle River Power, LLC

SUBMITTED 12/06/2021, 04:09 PM

Contact
Brian Theaker (btheaker@mrpgenco.com)

1. **Please provide a summary of your organization's comments on the issue paper and straw proposal.**

   Middle River Power (MRP) understands the CAISO's goal to investigate changes required to facilitate the addition of the central procurement entity (CPE). MRP generally agrees that the CPE should have its own scheduling coordinator (SC) ID so that suppliers can submit supply plans to the CAISO for validation purposes. MRP also believes that allowing the CPE to be an SC would allow the CPE to schedule into the CAISO's energy markets if and when the CPE procures resources with energy dispatch rights. However, the proposal to allocate backstop procurement costs to the CPE seems to have little benefit because it would only apply only to two out of six CAISO backstop procurement tariff authorities but would not apply to reliability must run cost allocation.

   MRP believes the inclusion of changes to RAAIM is inappropriate for this initiative as it does not impact the CPE in any form. MRP understands the CAISO's desire to modify RAAIM but that should be scoped either within the Resource Adequacy Enhancements initiative or another independent initiative.

2. **Please provide comments on the system and local obligation for CPE and LSEs with load in multiple TAC Areas.**

3. **Please provide comments on the allocation of system and flexible attributes of Local RA Resources.**

4. **Please provide comments on the clarification of CPM Process and Cost Allocations.**

5. **Please provide comments on the RAAIM settlment process enhancements.**

   The CAISO has proposed to eliminate the monthly roll-over of RAAIM unavailability charges to future months so that it can avoid a situation in which the CAISO has insufficient carry-forward funds to refund to a resource due to an error that caused for a resettlement. Currently, those rollovers allow unavailability charges to be used to fund availability incentive payments to RA resources that are available in a month more than two points above the CAISO's availability target of 96.5% (i.e., have availability greater than 98.5%).

MRP opposes this proposal for many reasons.

First, this matter is outside of the scope of purported topic of this initiative – CPE implementation. If the CAISO believes that RAAIM modifications are warranted, it should devote a separate, dedicated initiative to considering those changes. Given the fact that the CAISO proposed to eliminate RAAIM in the RA Enhancements initiative that began in late 2018, it is unclear why the CAISO is now proposing to modify RAAIM in the CPE implementation initiative.

Second, the CAISO's proposed solution does not solve the problem because it is still possible that unallocated RAAIM charges are insufficient to pay a refund on a monthly basis. While the CAISO attempted to explain its reasonings to FERC for its waiver, it's unclear why the CAISO does not propose to resettle the RAAIM incentive payments for all resources that received such payments. To MRP's knowledge, this resettlement has occurred only once. MRP requests the CAISO provide additional information to help stakeholders understand whether such a change is truly necessary.

Third, the CAISO's RAAIM penalty and incentive structure is already asymmetrically biased by the rule that funds RAAIM availability incentive payments only to the extent that the CAISO has collected RAAIM unavailability charges. Eliminating the carryover rule would further bias the RAAIM penalty and incentive structure. The CAISO's RAAIM penalty and incentive structure is already further biased against RA capacity suppliers by the CAISO's selection of a 96.5% availability target. By the CAISO's own admission, this availability target no longer represents a reasonable forced outage rate. CAISO witness Jeff Billinton's January 11, 2021 testimony In CPUC Rulemaking R.20-11-003 includes this statement: "The GADS [NERC's Generator Availability Data System] forced outage rate is a reasonable industry accepted measure of expected forced outages and I recommend that a 7.5% forced outage rate be used to allow for a more appropriate amount of expected forced outages."[1] The CAISO's current RAAIM availability target of 96.5% is four percentage points higher than what the CAISO told the California Public Utilities Commission it believes is a reasonable availability target. And while the CAISO also applies a 2% "dead band" to this availability target – meaning that it neither penalizes availability above 94.5% nor rewards availability below 98.5% - the 94.5% RAAIM availability target is clearly above what the CAISO believes to be a reasonable forced outage rate. If the CAISO is going to make any changes to RAAIM, it must also revise this availability target.

Fourth, the CAISO offers several other reasons as to why the carryover rule should be eliminated that are unavailing. The CAISO observes that "This carry-forward mechanism allows the resource that was penalized in one month to receive an allocation of funds in the future month."[2] This was found to be just and reasonable by FERC because the CAISO explained that "RAAIM is a mechanism to incent resource adequacy resources to comply with their must-offer obligations."[3] Given the monthly structure of availability assessments, this argument carries no weight. There is no logical reason as to why a resource that was charged for unavailability in one month should not be eligible for availability incentive payments in a different, separately-assessed month. If the CAISO believes that a resource that is penalized for non-availability in one month should not be eligible for RAAIM incentive payments in a later month, then the CAISO should have structured RAAIM to apply over a period longer than a month. Would the CAISO assert that a resource that incurs a RAAIM non-availability charge in a non-peak load month like February in which there is likely a great surplus of available non-RA capacity, but later earns a RAAIM availability incentive payment in a peak load month like August in which there is no surplus of non-RA capacity is not, across the course of an entire operating year, providing an overall net benefit to the CAISO and to California load? If the CAISO truly believes that it is somehow unseemly for a resource that incurred a non-availability charge in one month to earn an availability incentive in a later month, it should not just eliminate the monthly carryover rule, but should restructure the RAAIM structure to apply over a longer period.

The CAISO also asserts that "This carry-forward mechanism also allows an SC to hedge against its RA obligation. A scheduling coordinator with more than one RA resource in its portfolio can hedge against the penalty by ensuring that at least one or more of the other RA resources meet their obligations."[4] This statement is unfounded and unsupported by any fact in the proposal. This objection is irrelevant given that the CAISO assesses RAAIM charges on a *resource-specific* basis. There is nothing unseemly about individual resources earning RAAIM incentive payments that may, within a given scheduling coordinator's portfolio, offset RAAIM non-availability charges incurred by a separate resource within that scheduling coordinator's portfolio. This objection is not an objection about the carryover rule, but about the resource-specific application of RAAIM.

Again, if RAAIM is not accomplishing what the CAISO believes it should accomplish, the CAISO should conduct a stakeholder process to develop a new RAAIM design. Eliminating the monthly carryover by itself merely exacerbates the asymmetric nature of this penalty and incentive structure.

If the CAISO insists on eliminating the monthly carryover, the CAISO must also take two additional steps to rebalance the RAAIM structure:

1. The CAISO must reset the monthly RAAIM availability target to 92.5%, consistent with its testimony in the Emergency Reliability rulemaking. The CAISO may continue to apply a 2% dead band, but

the dead band should be centered at 92.5%.

2. The CAISO must drop the rule that allows the CAISO to provide RAAIM incentive payments only to the extent that it has collected non-availability charges. Recent events, like the rolling blackouts in August 2020, have brought to light the increased importance of resource adequacy. Increased availability of RA resources provides a tangible, direct benefit to California load. RAAIM incentive payments that are not offset by RAAIM non-availability charges should therefore be allocated to metered demand.

For all these reasons, MRP opposes the proposal to eliminate the RAAIM monthly carry-over.

[1] *Testimony of Jeff Billinton on Behalf of the California Independent System Operator Corporation*, submitted January 11, 2021 in California Public Utilities Commission Rulemaking R.20-11-003, at page 4, lines 14-16.

[2] Issue Paper and Straw Proposal at page 15.

[3] Transmittal Letter to ER15-1825 at page 5

[4] Id. The CAISO reiterated this purported benefit on page 16 of the Issue Paper and Straw Proposal: “Third, eliminating the monthly roll-over rule should increase the effectiveness of RAAIM by ensuring that a resource’s performance in a given month is either paid or charged for that month and not cross-subsidized by another month’s performance.”

6. Please provide comments on the EIM Govering Body classification.

7. Please provide any additional input not included above related to the issue paper and straw proposal.

Pacific Gas & Electric

SUBMITTED 12/06/2021, 04:57 PM

Contact
Matt Connolly (mhco@pge.com)

1. Please provide a summary of your organization's comments on the issue paper and straw proposal.

Pacific Gas & Electric Company (PG&E) appreciates the CAISO’s efforts in this initiative to update the tariff language and CAISO software to accommodate a Central Procurement Entity (CPE) construct. PG&E supports many of the CAISO’s proposals outlined in the Straw Proposal; however, PG&E requests CAISO’s consideration of the following alternatives and clarifications, specifically:

A. Capacity Procurement Mechanism (CPM) cost allocation for individual local RA deficiencies should be determined by a methodology established by the Local Regulatory Authority (LRA). PG&E supports CAISO’s proposal to not modify the collective local RA deficiencies CPM tariff language and, instead, proposes that the tariff language in Section 43A be modified to allow CPM cost allocation for individual local RA deficiencies to initially be determined by a methodology established by the LRA and only default to the CAISO’s methodology if a methodology has not been established by the LRA.

B. The CAISO should provide clarification on the engagement and timeline as part of the California Public Utilities Commission (CPUC) process, as laid out in the Scoping Memo and Ruling in Rulemaking 21-10-002. Given the very tight timeframe between the start of this CAISO initiative and the expectation to request tariff approval at FERC, PG&E urges additional attention to the coordination with the CPUC process. The current comment period for this specific straw proposal is well ahead of the comment and proposal process as part of the CPUC Scoping Memo, and workshop. To that end, PG&E would like to see CAISO layout the CAISO timeline and expected engagements across the CAISO and CPUC processes.

2. Please provide comments on the system and local obligation for CPE and LSEs with load in multiple TAC Areas.

In the Issue Paper and Straw Proposal – Central Procurement Entity Implementation, CAISO proposes to exempt a CPE from Section 40.3.2(a) that effectively caps the local RA obligation at the CPE’s system RA obligation and believes that this is needed because the CPE may not be an LSE with corresponding load to serve (e.g., a zero MW system RA obligation). PG&E supports this exemption for the CPE and believes that exempting the CPE from this tariff provision is consistent with the CPUC’s adoption of the hybrid procurement framework adopted in Decision (D.) 20-06-002.

Related to this exemption for the CPE, CAISO also proposes to modify Section 40.3.2(a) and develop software enhancements to allow for LSEs with load in multiple TAC areas to cap an LSE's local RA obligation at their applicable demand and reserve margin requirements in each TAC area for the applicable month. PG&E has concerns with this aspect of the proposal when considering the CAISO's suggested solution that includes modifying D.20-06-002 to allow the CPUC to re-allocate the local RA obligation to those LSEs that agree to voluntarily show their self-procured resources. For example, if an LSE has load in multiple TAC areas, there could be a scenario where CAISO does not appropriately account for the local RA obligation. As an example, PG&E outlines a potential scenario in Table 1 below.

Table 1 – LSE A with Load in TAC A and TAC B

	Load	Self-Shown Resources	Re-Allocation of Local Obligation	Difference
TAC A	100 MW	20 MW	20 MW	-
TAC B	20 MW	30 MW	20 MW	(10) MW
Total	**120 MW**	**50 MW**	**40 MW**	**(10) MW**

CAISO's suggested solution to allow the CPUC to re-allocate the local RA obligation coupled with the proposal to modify Section 40.3.2(a) for LSEs with load in multiple TAC areas could present gaming opportunities. In the potential scenario above, LSE A could be incented to self-procure more resources in one TAC area to artificially cap its re-allocated local RA obligation amount and effectively remove the entire local RA obligation to show those resources to the CAISO. Additionally, because Section 40.3.2(a) requires the CAISO to allocate the difference of the local RA obligation to all CPUC-jurisdictional LSEs on a proportional share basis, those LSEs would then be assigned a local RA obligation and will be required to make up the difference through additional procurement.

Additionally, PG&E requests further clarification on the number and size of the LRAs that oversee multiple LSEs, and the need to generalize the tariff language to account for the possibility of another LRA other than the CPUC establishing a new CPE.

3. Please provide comments on the allocation of system and flexible attributes of Local RA Resources.

PG&E supports CAISO's proposal to implement separate fields in the LRA Credit templates in CIRA to accept and validate system and flexible RA CPE credits (similar to existing system CAM credits) and believes this is consistent with the CPUC's adoption of the hybrid procurement framework adopted in D.20-06-002.

4. Please provide comments on the clarification of CPM Process and Cost Allocations.

PG&E supports CAISO's proposal to not modify the tariff language as it relates to collective local RA deficiencies CPM, but has concerns, for the reasons outlined in these comments, with the CAISO's suggestion to follow the principle where the CPM cost allocation for an individual local RA deficiency will only follow the entity assigned the local RA obligation. PG&E believes that sole reliance on this principle could result in unintended consequences. Moreover, the self-shown concept of the hybrid procurement framework is scoped within the RA proceeding and any changes adopted in the CAISO's tariff language must be flexible enough to accommodate any modifications to the CPE structure that are ultimately adopted at the CPUC.

As an alternative to CAISO's proposal, PG&E strongly recommends that the tariff language in Section 43A be modified to allow CPM cost allocation for individual local RA deficiencies to be determined by a methodology established by the LRA. This would allow flexibility in the tariff language that could encompass any proposal set forth and ultimately adopted in the RA proceeding at the CPUC and ensure timely implementation of a mechanism that can appropriately allocate any CPM-related costs due to individual local RA procurement deficiencies.

PG&E proposes that the language used in Section 43A.8.8.c "Allocation by Local Regulatory Authority Method" could be similarly applied to CPM cost allocation for individual local RA deficiencies. Modifying the language in the tariff sections for CPM cost allocation as it relates to local capacity areas based on an LRA-defined methodology will allow for increased flexibility needed to avoid future modifications to the tariff given the continuous development and refinement of the CPE structure. For example, the tariff language could state:

Calculation of Deficiency by LRA

> "The CAISO will determine whether each Local Regulatory Authority (LRA) met its allocable share of the Local Capacity Need based on the cumulative amount of Local RA Capacity that LRA's jurisdictional Load Serving Entities or CPE included in their annual and monthly Local RA Capacity Plans in total and included in their monthly Local RA Capacity Plans for each Local Capacity Area."

Allocation by Local Regulatory Authority Method

> "If Load Serving Entities or CPEs jurisdictional to a Local Regulatory Authority have an individual local RA deficiency under Section 43A.2.1 and the Local Regulatory Authority has established its own methodology for allocating the Local Capacity Need to its jurisdictional Load Serving Entities, the CAISO will use the Local Regulatory Authority's methodology to allocate the Local Capacity CPM costs to the Scheduling Coordinator of each Load Serving Entity that is jurisdictional to that Local Regulatory Authority and that failed to meet its procurement obligation. If the Local Regulatory Authority does not notify the CAISO of its allocation method by the deadline established in the relevant Business Practice Manual, then the CAISO allocates Local Capacity CPM costs using its default allocation methodology."

PG&E also notes that the Reliability Requirements Business Practice Manual may need to be updated to support the proposed tariff language outlined in this section and could state:

Application of LRA-Defined Methodology

> "The CAISO must receive advanced notice of this methodology in order to promptly complete its CPM process. Any LRA that chooses to identify its own LSE or CPE CPM cost allocation methodology must provide this methodology to the CAISO no later than the last business day in October prior to the compliance year; the CAISO will use this CPM cost allocation methodology for the entire compliance year."

Lastly, PG&E supports CAISO's proposal to keep the current language related to a collective local RA deficiency CPM the same where procurement costs from a collective local RA deficiency CPM are allocated pro-rata to all LSEs with load in that respective TAC area.

5. Please provide comments on the RAAIM settlment process enhancements.

PG&E strongly supports the CAISO's proposed enhancements to eliminate the RAAIM carry-forward mechanism. CAISO is well-justified to move to a more simple and fair process to distribute excess RAAIM funds. The need for CAISO to file a burdensome FERC waiver following settlement recalculations demonstrates one of the problems with the current mechanism.

6. Please provide comments on the EIM Govering Body classification.

PG&E supports the CAISO's proposal that the EIM Governing Body should not have an advisory role in this initiative.

7. Please provide any additional input not included above related to the issue paper and straw proposal.

In this section, PG&E seeks clarifications and provides comments on three items: (a) Requirements of the CPE as a Market Participant, (b) Re-Allocation of the Local RA Obligation, and (c) Alignment of Schedule with the CPUC Proceeding.

a. Requirements of the CPE as a Market Participant

PG&E seeks clarification on the proposed language and requirements that will apply to the CPE as a market participant represented by a scheduling coordinator related to the new sub-section in Section 4 of the tariff, including any details to the pro forma agreement that will need to be developed.

PG&E also seeks confirmation that the CPE will be able to net any credit requirements for establishing the new scheduling coordinator ID needed for the CPE with that of the Utility it operates under given that they are the same legal and financial entity.

b. Re-Allocation of the Local RA Obligation

PG&E notes that the local RA obligation is a single value, measured in MWs, that is applied equally across all months of the year. PG&E seeks clarification on how CAISO's suggested solution, which includes re-allocating the local RA obligation to LSEs that agreed to voluntarily show their self-procured resources, will be determined and distributed out to those LSEs. For example, if LSE A agrees to voluntarily show Resource Z for its entire NQC amount across all months of the year (notably, Resource Z has an NQC of 30 MWs in March and 50 MWs in August), it is not clear what the re-allocated local RA obligation amount will be and whether LSE A will have a single annual local RA obligation or a monthly local RA obligation.

c. Alignment of Schedule Between the CAISO's CPE Implementation Initiative and CPUC Proceeding

Given the very tight timeframe between the start of this CAISO initiative and the expectation to request tariff approval at FERC, PG&E urges additional attention to the coordination with the CPUC process. The current comment period for this specific straw proposal is well ahead of the comment and proposal process as part of the CPUC Scoping Memo, and workshop. To that end, PG&E would like to see CAISO layout the CAISO timeline and expected engagements across the CAISO and CPUC processes.

Southern California Edison

SUBMITTED 12/06/2021, 04:28 PM

Contact
Wei Zhou (wei.zhou@sce.com)

1. **Please provide a summary of your organization's comments on the issue paper and straw proposal.**

   Southern California Edison Company ("SCE") generally supports the CAISO's Central Procurement Entity ("CPE") Implementation issue paper and straw proposal ("CAISO Proposal") because the process it proposes for CPE local Resource Adequacy ("RA") procurement is reasonable. Specifically, SCE appreciates the CAISO Proposal's detailed stakeholder process and timeline to support implementation of a CPE process for the 2023 RA year. However, as discussed below, SCE recommends that the CAISO clarify the curing process for the CPE and load-serving entities ("LSEs") in the event of a deficiency.

2. **Please provide comments on the system and local obligation for CPE and LSEs with load in multiple TAC Areas.**

   SCE supports the CAISO Proposal for providing the CPE and LSEs with an opportunity to cure a deficiency under Section 40.7.***[1]*** However, it is unclear from the CAISO Proposal what the curing process would specifically entail and what requirements a LSE would need to meet.

   For example, CAISO's Proposal states that if the CAISO determines that a CPE's RA portfolio does not satisfy the Local Capacity Requirements ("LCR") after monthly and annual showing deadlines, resulting in a deficiency, an LSE in the CPE's territory can elect to cure a partial or full amount of the CPE deficiency.

   SCE recommends that in such a situation, the CAISO should clarify the LSE's must offer obligation and which entity will be responsible for showing the capacity to the CAISO. Additionally, the CAISO should clarify that any LSE can offer capacity to cure the deficiency, including an LSE outside the CPE's territory.

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   [1] CAISO Proposal, p. 12.

3. **Please provide comments on the allocation of system and flexible attributes of Local RA Resources.**

   SCE currently has no comments.

4. **Please provide comments on the clarification of CPM Process and Cost Allocations.**

   SCE currently has no comments.

5. **Please provide comments on the RAAIM settlment process enhancements.**

   SCE supports CAISO Proposal's proposed RAAIM enhancement to "allocate the excess based on activity in that trading month according to the allocation formula that currently applies to the year-end allocation"[1] rather than carrying over excess funds into the next month and reallocated annually.

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   [1] CAISO Proposal, pp. 15-16.

6. **Please provide comments on the EIM Govering Body classification.**

   SCE currently has no comments.

7. **Please provide any additional input not included above related to the issue paper and straw proposal.**

   SCE appreciates and supports the CAISO' Proposal's detailed and expedited timeline for a stakeholder process to establish and implement the CPE process for local RA.

Governor Gavin Newsom
1303 10th Street, Suite 1173
Sacramento, CA 95814

California Public Utilities Commission
505 Van Ness Ave.
San Francisco, CA 94102

December 08, 2021

RE: MCE Supports the Sustainable and Equitable Growth of Rooftop Solar, Particularly for Low-Income and Disadvantaged Communities, via the Net Energy Metering (NEM) 3.0 Proceeding

Dear Governor Newsom and CPUC Commissioners,

As one of the largest Community Choice Aggregators (CCA) in California, Marin Clean Energy (MCE) requests your support to ensure that rooftop solar coupled with storage continues to grow sustainably, and equitably, through the existing Net Energy Metering (NEM) 3.0 proceeding.

Robust adoption of distributed energy resources (DERs), such as solar plus storage, is fundamental in the fight against climate change. Further, increased solar plus storage adoption increases resiliency for the entire grid, and has the potential to lessen the impacts of the climate crisis via reductions in greenhouse gas emissions. High DER penetration also creates green jobs to benefit our communities.

NEM allows customers to power their homes, apartments, nonprofit organizations, businesses, cities, and schools using clean solar energy by giving them a bill credit for the excess clean electricity they send to the grid. Today, the sustainable and equitable growth of rooftop solar is under question. California's investor-owned utilities (IOU) and other parties in the proceeding are proposing to make changes which would impact the financial incentives of NEM customers.

Some studies show that historically, rooftop solar adoption has disproportionately benefited higher income, white, single-family homeowners.[1] MCE is focused on creating sustainable and equitable outcomes for our member communities. When determining the structure of the program under a NEM 3.0 framework, MCE urges you to consider those customers who have traditionally been excluded from the benefits of NEM, such as those who are lower-income and/or live in multi-unit dwellings and disadvantaged communities (DACs).

MCE is focused on getting battery storage, coupled with solar, into our communities to help with resiliency during emergency outages and PSPS events, and to improve grid health and reliability. Battery storage is especially important for medically vulnerable customers, critical facilities, and in DACs, where Public Safety Power Shutoff (PSPS) events have been an added burden. These battery solutions, coupled with solar, shift the benefits of solar to the evening, when the energy is needed most, and they reduce the need for fossil-based generation in the 4-9 pm timeframe. NEM solutions should bolster and incentivize storage to improve grid health and community resilience.

The proposed policy changes to NEM would make going solar more expensive to future customers, increase the amount of time it takes to pay off their investments and ultimately have the potential to limit the amount of rooftop solar (and solar plus storage) in California. Some of the proposed changes would also create monthly fixed fees that MCE customers could not avoid in their transmission and distribution charges to Pacific Gas & Electric (PG&E), regardless of the Net Surplus Compensation (NSC) that is provided by MCE.

In particular it is critical to consider impacts to our low-income communities like those in the California Alternate Rates for Energy (CARE) and Family Electric Rate Assistance (FERA) discount programs, who may wish to enroll in NEM but may be discouraged from doing so if the financial incentives are decreased too significantly.

To promote a sustainable and equitable NEM future, MCE urges a strong focus on incentivizing solar plus storage adoption (particularly among low-income customers and those living in DACs), avoiding punitive fees for installing solar, and ensuring any changes do not dissuade customers from installing battery storage. There may be a need for a modest grid-use charge for NEM customers who rely on the grid during non-solar hours, relative to their actual grid impact, to avoid cross-subsidization, but there should be no “penalty” fees for NEM customers. Any such grid-use charge should be carefully researched and developed before implementation to confirm it would not act as a disincentive to battery storage adoption.

Therefore, we oppose any CPUC proposal that imposes a penalty fee on past or future solar and solar + storage adopters. It is critical that low- and middle-income customers (including

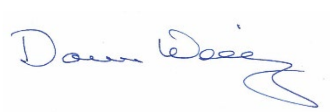
[1] Barbose, Galen L., *et al.* Residential Solar-Adopter Income and Demographic Trends: 2021 Update. Lawrence Berkeley National Laboratory (LBNL), Berkeley, CA 2021.

homeowners and renters) as well as those living in disadvantaged communities are not discouraged from enrolling in NEM programs. Potential solutions to consider include:

- Expanding NEM benefits for residents with household incomes at or below 80 percent of the area median income**,** as determined by the Department of Housing and Community Development;
- Exempting low-income customers, especially those that live in High Fire Thread District (HFTD) areas or DACs, or those who have experienced multiple PSPS events from additional fixed charges.
- Providing stronger incentives for low-income customers that live in HFTD areas to install solar plus storage systems;
- Exempting low-income customers and those who live in DACs from additional fixed charges;
- Providing stronger upfront incentives for low-income customers and those who live in a DAC to install solar plus storage systems; and
- Exempting customers who install batteries from any proposed fixed charges (and providing compensation for those DERs), as their batteries provide additional grid benefits.

California has long been a model for the clean energy transition, and what happens here will inform the clean energy landscape across the United States. As we emerge from the economic and public health crises caused by COVID-19, MCE urges you to maintain the benefits of solar energy for all Californians when storage is included, ensure that rooftop solar plus battery storage continues to grow sustainably and equitably, and focus investment on the ratepayers and communities who are at the forefront of the social justice and climate crisis.

Sincerely,



Dawn Weisz, Chief Executive Officer

Cc: Members of the California Public Utilities Commission

FILED
12/09/21
03:53 PM

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

OPENING COMMENTS OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON ALJ RULING REGARDING PCIA FORECASTING DATA ACCESS

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On behalf of
California Community Choice Association

December 9, 2021

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

OPENING COMMENTS OF
THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION
ON ALJ RULING REGARDING PCIA FORECASTING DATA ACCESS

Pursuant to Administrative Law Judge (ALJ) Wang's November 5, 2021 e-mail ruling (ALJ Ruling), the California Community Choice Association[1] (CalCCA) hereby submits these comments providing further detail regarding its data transparency proposal. CalCCA proposes the use of a non-disclosure agreement (NDA) that would allow community choice aggregators (CCAs) and other entities whose customers pay the Power Charge Indifference Adjustment (PCIA) to access: (1) confidential, resource-specific volumetric data underlying the PCIA, and (2) prior-year workpapers underlying PCIA rates, year-round and for the limited purpose of forecasting PCIA rates.[2]

All load-serving entities (LSEs) strive for rate stability for their customers. Current data access protocols, however, leave unbundled customers materially less protected from rate spikes

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[1] California Community Choice Association represents the interests of 23 community choice electricity providers in California: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

[2] *See* Rulemaking (R.) 17-06-026, Opening Comments of the California Community Choice Association on Data-Related PCIA Issues (Oct. 1, 2021).

than bundled customers. CalCCA's proposal therefore aims toward one simple objective: rate stability for CCA customers, which will put those customers on an equal footing with bundled customers. CCAs will be better positioned to achieve that objective if they have access to detailed and timely information regarding PCIA inputs. With that data, if PCIA rates are forecasted to increase, a CCA may plan to apply its liquidity to maintain CCA rates at a level that—when combined with the PCIA—does not lead to rate shock in its customers' total generation rate. If on the other hand PCIA rates are forecasted to decrease, a CCA may be able either to lower customer rates or maintain stable rates and accrue reserves to prepare for another upward PCIA rate cycle. CalCCA's data transparency proposal therefore presents a reasonable approach to confidentiality that will better protect unbundled customers without compromising the IOUs' bundled customers' interests. The Commission should adopt CalCCA's proposal.

I. FORECASTED 2022 RATES SHOW HOW MISMATCHES IN DATA ACCESS CREATE A CONSUMER PROTECTION ISSUE FOR UNBUNDLED CUSTOMERS.

A. Both Bundled and Unbundled Customers Pay the PCIA, but the Commission's Current Data Access Protocols Leave Unbundled Customers Materially Less Protected From Changes in the PCIA Than Bundled Customers.

While both bundled and unbundled customers pay the PCIA, the Commission's current data access protocols leave unbundled customers materially less protected from changes in the PCIA than bundled customers. Whereas the utility has access to data underlying the Indifference Amount calculation and PABA balance at all times and can therefore forecast trends in PCIA rates, the CCAs' Reviewing Representatives (RRs) only have access to the same data during the six months in which Energy Resource Recovery Account (ERRA) Forecast proceedings are litigated. Moreover, the IOUs require the CCAs to enter into a docket-specific NDA during ERRA proceedings that prohibits the use of such data outside the confines of that proceeding.

Access to the data underlying PCIA rate projections and accrued PABA balances during the pendency of an ERRA proceeding, therefore, is not sufficient to ensure rate stability for CCA customers because that data is not available year-round and cannot be used for PCIA rate forecasting once the rates proposed in the applicable proceeding are set (via the resolution of that proceeding). This creates a fundamental imbalance between the IOUs' bundled customers, whose LSEs can plan for steep increases in the PCIA, and unbundled customers, whose providers do not have access to the year-round data necessary to plan for PCIA rate spikes.[3]

B. The Forecasted Decrease in 2022 PCIA Rates Provides a Useful Example to Illustrate the Urgent Need for Greater Transparency in the Data Underlying the PCIA.

In the IOUs' currently-pending ERRA Forecast proceedings (establishing 2022 revenue requirements and forecasting 2022 rates), the IOUs each forecast dramatic decreases in the PCIA. This represents a marked departure from historic trends—in PG&E's service territory, for example, prior to 2022, the PCIA had increased every year for over a decade. In general, the decrease in 2022 PCIA rates is driven by two key factors: (1) a dramatic rise in the "brown power benchmark" (an administratively established proxy value that is used to calculate the IOU's portfolio market value), which in turn significantly decreases the IOUs' forecasted Indifference Amounts for 2022, and (2) 2021 overcollections in the PABA which will be refunded to customers through the 2022 PCIA rates.

PG&E's "November Update" to its 2022 ERRA Forecast Application details the primary drivers for 2021 overcollections in the PABA in a table reproduced below.[4]

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3 This imbalance is particularly salient in the absence of a cap on the PCIA.
4 A.21-06-001, PG&E-5 at 16 (Nov. 8, 2021).

Table 1: PABA Driver Analysis in PG&E's 2022 ERRA Forecast November Update

TABLE D
PRIMARY DRIVERS FOR PABA OVERCOLLECTION SUMMARY
(MILLIONS OF DOLLARS)

Line No.	Description	Approximate Impact (Over)/ Under Collection	
1	Increase in Expected Net California Independent System Operator (CAISO) Revenues		
	(a) Higher Market Electricity Prices	$(1,050)	
	(b) Less Generation from PCIA-Eligible Resources	330	
	Subtotal		$(720)
2	Higher Procurement Cost		
	(a) Higher Fuel Costs for Natural Gas-fired Generators	$110	
	(b) Lower Capacity Costs Driven by Unplanned Outage	(95)	
	(c) RPS Contract Procurement Costs	85	
	Subtotal		$(100)
3	Higher Recorded Undercollection Brought Forward From 2020		
	(a) Lower-Than-Expected Recorded Customer Revenues	$125	
	(b) Net Impact from Lower Recorded CAISO Revenues and Lower Procurement Costs	50	
	(c) Greater-Than-Expected ERRA Overcollection Transferred to PABA	(30)	
	Subtotal		$145
4	Authorized 2021 RTBA-E Balances in D.20-12-005		$153
5	Higher Customer Revenue		$(75)
6	RA Market Value		
	(a) 2021 Final RA Adder	$(50)	
	(b) PCIA Template Line Loss Issue	35	
	Subtotal		$ (15)
7	RPS Market Value		
	(a) 2021 Final RPS Adder	$5	
	(b) Lower RPS Sales	(10)	
	Subtotal		$(5)
8	Recorded One-Time Adjustments		
	(a) Recorded One-Time Adjustments discussed in PG&E's June Prepared and August Revised Testimony		
	(1) Cumulative Authorized Balancing Account Transfers(a)	$(41)	
	(2) Updated 2020 RTBA-E Transfers	35	
	(3) Adjustments to Pension Revenue Requirement and donations of hydro facilities	(24)	
	(b) One-Time Adjustments recorded in May through September		
	(1) 2019 Diablo Canyon Seismic Studies Balancing Account (DCSSBA) and 2020 Wildfire Mitigation Balancing Account (WMBA) Transfers	6	
	(2) Loss on Chili Bar Hydro Sale	10	
9	Other		$(20)
10	Forecast 2021 Year-End PABA balance, Prior to Transfer from ERRA-Main		$(451)

The above Table 1 demonstrates the several separate factors that drive collections in the PABA, many of which have countervailing impacts on the PABA balance. For instance, whereas higher market electricity prices contributed a $1,050 million overcollection in the PABA on Line 1(a), a decrease in generation from PCIA-eligible resources contributed a partially offsetting $330 million undercollection in the PABA on Line 1(b). The total 2021 Year-End PABA balance was expected to be a $451 overcollection, despite several individual factors listed in Table 1 contributing an undercollection to the overall PABA balance.

It is clear from this table that—given the myriad, generally independent drivers underlying the PABA—insight into a single factor such as higher electricity prices, or even the total PABA balance, would not be informative of where the PABA is likely to stand by the end of the year. A detailed, disaggregated analysis of drivers for collections in the PABA—*i.e.*, the type of analysis provided in the table above—is necessary in order for CCAs to understand anticipated changes in the PABA and take timely actions to protect unbundled customers from rate shock. That analysis cannot be conducted without the confidential data CalCCA requests via its proposal and currently only the IOUs have year-round access to that data.

The IOUs suggest—and the CCAs agree—that there is a substantial risk that the market price of non-RPS (brown) power, which primarily caused 2022 PCIA rates to plummet, will drive PCIA rates to an extreme increase in 2023.[5] Beyond the market price of brown power, a number of different factors over the course of 2022 will influence the PABA balances and other PCIA-inputs. In order to protect their customers and keep rates stable, therefore, the CCAs will need to plan for anticipated increases in the PCIA in 2023. But for half of 2022, the only data the CCAs will be able to view when attempting to plan for 2023 is the IOUs' total PABA balance, based on their public reports. The CCAs would have no insight into the degree to which some of

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[5] *See* Application (A.) 21-06-003 (SCE 2022 ERRA Forecast case), Exh. SCE-5 at 114:10-14 (While SCE is obligated to set PCIA rates on a forecast basis using the $65.93/MWh Energy Index provided by the Energy Division, the use of such a high Energy Index appears to significantly overstate the Energy Value of SCE's renewables-heavy PABA-eligible resources and <u>is likely to result in a sizeable undercollection in the PABA in 2022 that will have to be recovered in 2023 PCIA rates</u>." (emphasis added)).

the factors in Table 1 might be countervailing or augmenting impacts from brown power prices, for example, until they are able to conduct discovery in the IOUs' 2023 ERRA Forecast proceedings. Unless the Commission adopts CalCCA's transparency proposal, the CCAs will be blind to the individual factors driving the total PABA balance, with no sense of the degree to which the PABA balance will increase, decrease, or stay the same by the end of 2022.

These comments use the forecasted decrease in PCIA rates in 2022, and the expected rebound in those rates in 2023, as a helpful illustrative example to answer the ALJ's questions and demonstrate:

- Why PCIA rates impact unbundled customers significantly more than bundled customers;
- How CCA reserves can be used to absorb PCIA rate spikes;
- Why CalCCA's proposal illuminates otherwise opaque factors that drive the PABA;
- How CCAs can leverage knowledge of those changing drivers to put consumer protections in place;
- The dangers that an imbalance in access to data can create for unbundled customers;
- The need for further transparency in order to provide unbundled customers the stability that bundled customers enjoy;
- How RRs only need to present the drivers in the same manner parties, including the investor-owned utilities (IOUs), present them in public testimony; and
- Why CalCCA's proposal does not increase the risk of disclosure of confidential data.

II. RESPONSES TO THE ALJ'S QUESTIONS

Question 1. Access to Confidential PCIA and PABA Data Year-Round Enables CCAs to Prevent Rate Spikes for Customers.

In comments on the September 2021 ruling, CalCCA asserted that CCAs need access to confidential PCIA forecasting data to enable CCAs to *"absorb" spikes in the PCIA by reducing the generation rates they charge for their own procured power.*

How will access to confidential PCIA and PABA rate forecasting data year-round enable CCAs or Direct Access providers to prevent rate spikes for customers?

Please provide a detailed explanation, including (a) an explanation of how a CCA or Direct Access provider would use PCIA and PABA rate forecasts during each quarter of the year to protect customers from rate spikes, and (b) an analysis of the impact of having more accurate estimates (rather than less accurate estimates based on public data) on a CCA's or Direct Access provider's ability to protect customers from rate spikes during each quarter of the year.

a) Changes in PCIA rates can have a greater impact on unbundled customers than on bundled customers.

In order to explain the importance of access to year-round PCIA and PABA data for unbundled customers, it is necessary to first explain how the PCIA can have a greater impact on unbundled customers than on bundled customers. Generation rates for an IOU's bundled customers include an ERRA component that recovers the "at-market" cost of resources used to serve load. Typically, this includes the cost of purchasing energy on the wholesale market, the cost of renewable attributes retained to meet Renewable Portfolio Standard (RPS) obligations (Retained RPS), and the cost of capacity retained to meet Resource Adequacy (RA) obligations (Retained RA). In addition to the ERRA component, bundled customers' generation rates also include the PCIA, which recovers the "above-market" costs of the IOU's existing supply resources (the costs of those resources, less the market value of those resources). This creates an inverse relationship between market costs and the PCIA that serves as a natural hedge against volatility in the PCIA for all customers.

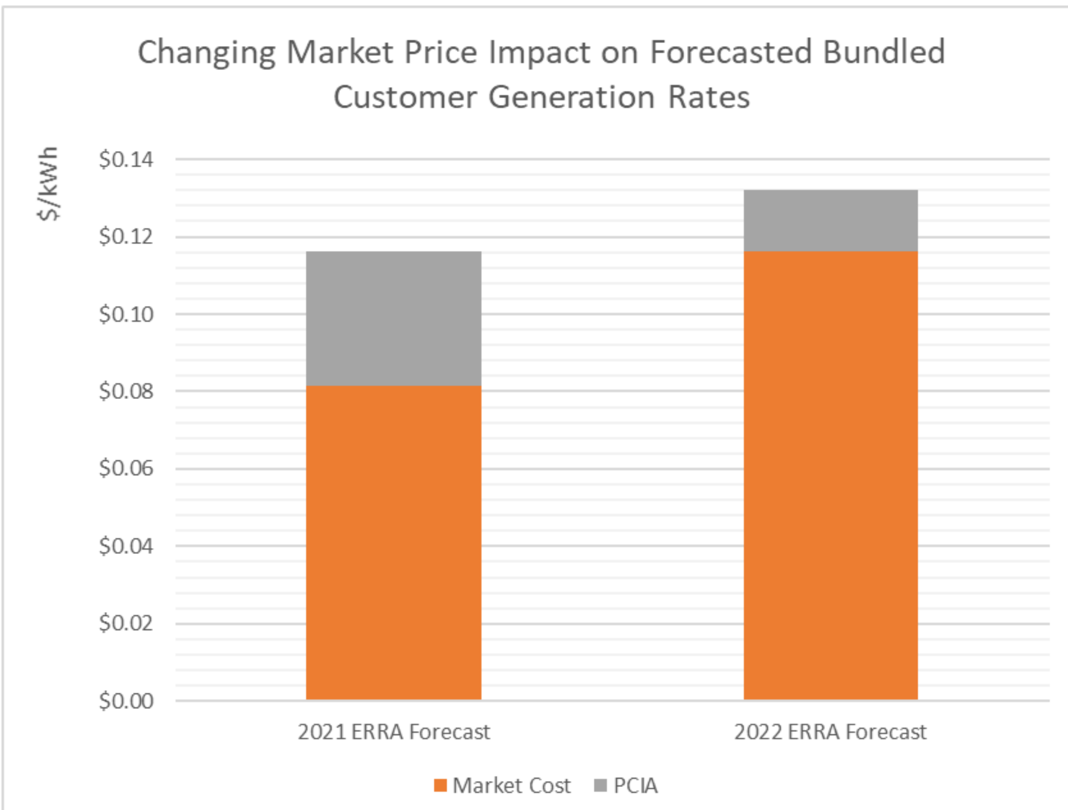
However, that hedge is *much* more effective for bundled customers than unbundled customers on account of three factors: (1) most resources within the IOUs' portfolios are older, long-term contracts and utility-owned generation that are now PCIA-eligible; (2) PCIA-eligible resources retained to serve bundled customers are valued at benchmarks tied to market costs, meaning the portion of the IOUs' portfolios that is "at-market" and charged via the utility's ERRA rates shifts as market costs rise and fall; and (3) the above-market portion of the IOUs' portfolios are shared by both bundled and unbundled customers via the PCIA. As a result, the PCIA and ERRA rates bundled customers pay largely countervail each other. A large increase in the ERRA portion of a bundled customer's rates does not equate with a large increase in the overall generation rate a bundled customers sees on their bill because of the related, counter-vailing decrease in the PCIA.

In contrast, CCAs are entering into long-term contracts to build new resources in response to local and Commission mandates (but the local mandates are more relevant here). The cost of these long-term contracts is fixed, and unbundled customers pay the entire cost of the projects—plus the PCIA—regardless of the market rates for energy and capacity. As a result, the PCIA and 'market' generation rates unbundled customers pay may countervail each other, but to a much smaller degree than for bundled customers. A large increase in the PCIA will have much more of an impact on the overall generation rate for an unbundled customer, especially when that CCA has executed long-term contracts to serve most of its load.

A final factor, short-term purchases, also influences how much market costs impact bundled and unbundled customer rates. Both the IOUs and the CCAs utilize the same market to procure or sell energy they need in the short-term. If those costs increase, the generation rates for both bundled and unbundled customers increase. However, an LSE that relies more on short-term purchases to serve load will see market cost drive generation rates more so than an LSE that relies on long-term fixed contracts.

The result of these different moving pieces is that bundled customers enjoy a much more helpful inverse relationship between market costs and the PCIA than do unbundled customers. This year's PCIA rates provide an example of how, when wholesale power costs are high, the IOUs' costs to serve load in ERRA rates rise but the PCIA falls, largely muting the rise in the IOUs' ERRA rates. This can be seen in Figure 1 below, which is based on PG&E's most recent ERRA forecast cases (but excludes the change in bundled customer rates due to the true-up of the prior year's balancing account balances):[6]

Figure 1



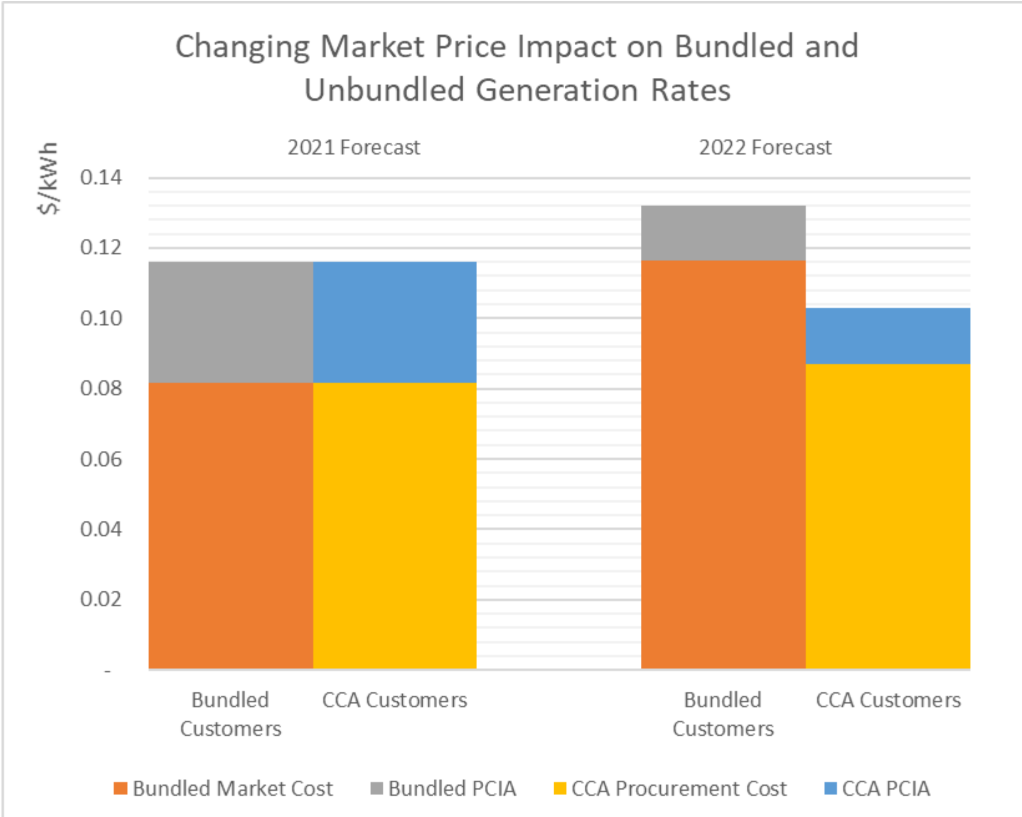
The difference between the bundled generation rates (the orange box plus the gray box) from 2021 (11.6 cents) to 2022 (13.2 cents) is an approximately 1.6-cent increase. However, the

[6] The rates in Figure 1 represent the forecasted ERRA rates plus the forecasted PCIA for those two years; the figure does not include the change in rates on account of the true-up of the prior year's balancing account balances.

difference between the “market cost” portion of the bundled generation rate that is recovered via ERRA (the orange box) from 2021 (8.2 cents) to 2022 (11.6 cents) is approximately 3.5 cents. The corresponding decrease in the PCIA absorbs 1.9 cents of the 3.5-cent increase in “at-market” generation rates. That is, the change in the market-tied benchmarks increases the at-market portion of the cost and decreases the above-market portion of the cost, cancelling each other out to a large degree. When ERRA rates went up by 3.5 cents, overall generation rates for bundled customers only went up by 1.6 cents (excluding the change in bundled customer rates due to the true-up of the prior year’s balancing account balances).

For CCA customers, a similar counter-acting effect exists between the PCIA and generation costs, but CCAs' long-term procurement diminishes the market cost impact such that changes in the total unbundled customer generation rates are mostly related to changes in the PCIA. This can be seen in Figure 2 below, which utilizes a theoretical CCA portfolio that has executed sufficient long-term contracts to meet all of its load requirements. The first item to notice is the difference between the “market cost” portion of the unbundled generation rate (the yellow box) from 2021 (8.2 cents) to 2022 (8.6 cents) is only 0.4 cents. There is almost no change because in this simplified example the CCA has executed long-term contracts to meet its load, and the cost of those contracts does not change with the market.

Figure 2



The second item to notice is that the difference between the overall generation rates (the yellow box plus the blue box) for CCA customers from 2021 (11.6 cents) to 2022 (10.2 cents) is approximately 1.4 cents. This change in the overall generation rate is almost entirely tied to the change in the PCIA, which drops 1.8 cents between 2021 (3.4 cents) and 2022 (1.6 cents).

changing market prices is concentrated in the PCIA itself (where a 1.8-cent change in the PCIA results in a 1.4 cent rate change).

Unbundled customers and the LSEs that serve them, therefore, have a particularly acute interest in analyzing trends in the PCIA, forecasting increases in PCIA rates, and taking actions where possible to mitigate rate shock (as these comments discuss in the next section, below). Moreover, PCIA rates are a major component of the generation rates that unbundled customers pay—as high as $0.047/kWh in 2021 for residential customers within the three IOUs' service territories. The PCIA therefore materially affects the total generation rates that CCAs charge their customers, and requires the CCAs to keep tabs at all times on the direction in which the PCIA is heading. This further underscores the importance of timely and detailed insight into the drivers of future PCIA rates for unbundled customers and the LSEs that serve them.

b) IOUs have data that will allow them to forecast PCIA rates, whereas CCAs lack access to the same data.

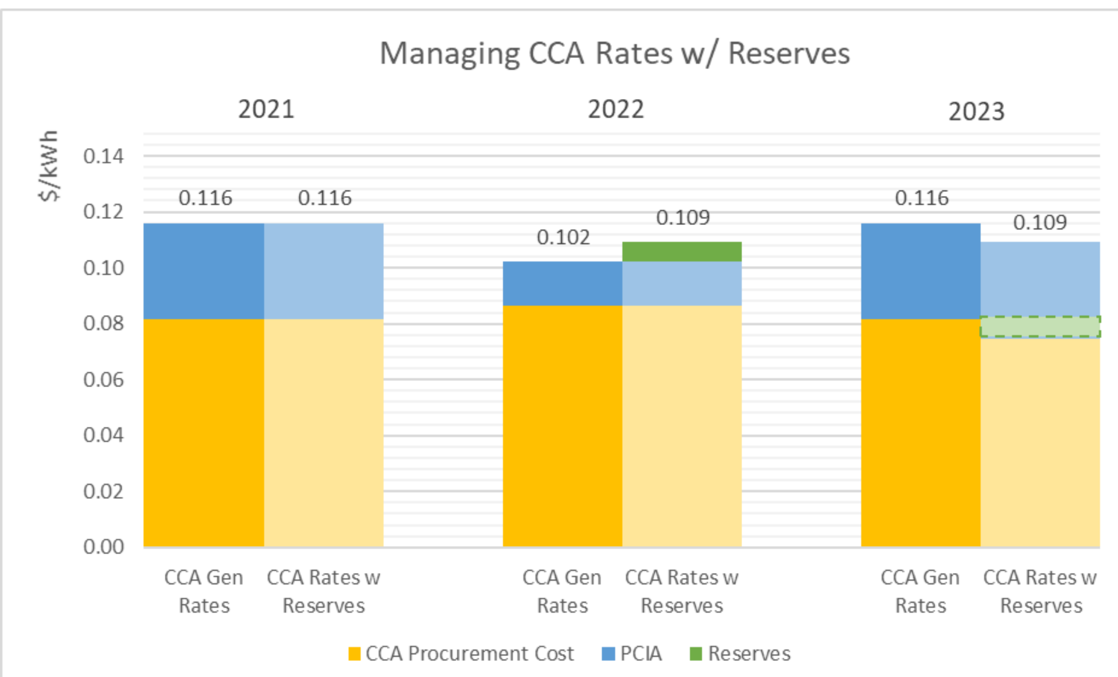
While the PCIA can have a greater impact on unbundled than bundled customers, the IOUs have greater access to data underlying the PCIA than CCAs. More specifically, IOUs have access to resource-specific volumetric cost and revenue data underlying individual factors driving PABA over- or under-collections, and therefore have the ability—on any day of the year—to assess where PCIA rates are headed in the next year.

In stark contrast, the CCAs have no access to the data underlying PCIA rates until the IOUs' ERRA Forecast proceedings begin (typically in June or July of any given year). At that point, CCAs may conduct discovery to access confidential cost and revenue data underlying the PCIA, but per the terms of NDAs that govern those proceedings, are not allowed to use that data outside of the proceeding (*i.e.*, for forecasting purposes). While CCAs have access to the publicly available *total* PABA and ERRA balances for the prior month, without information to help understand the individual, disaggregated drivers of those balances it is difficult for the CCAs to forecast how those balances might change over time. It makes no sense to keep CCAs and unbundled customers in the dark for half of the year.

c) Access to year-round data would allow CCAs to better utilize their reserves to modify generation rates to promote rate stability for their customers.

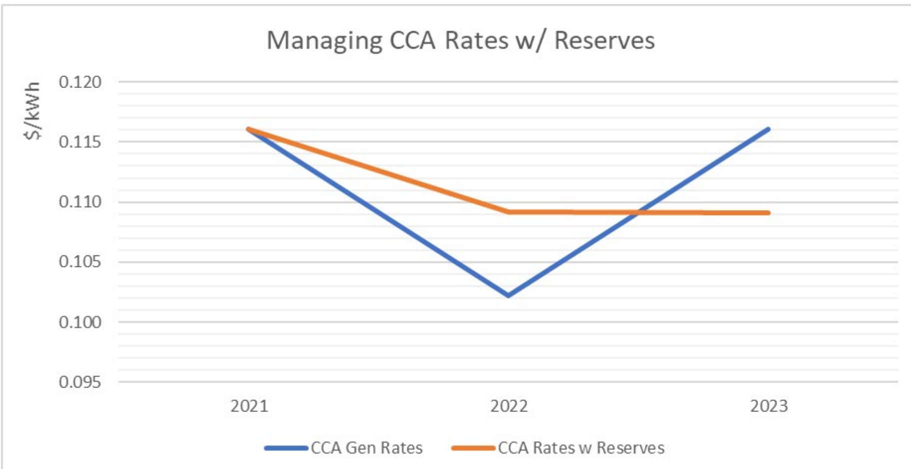
If CCA RRs had access to resource-specific volumetric data, and CCAs had access to the drivers underlying the PABA balance year-round, it would allow them to take action in order to protect their customers from spikes in the PCIA. In general, CCAs can apply their liquidity (*i.e.*, their reserves) to reduce the "at-market" portion of their rates in order to mitigate rate shock in the total generation rate. For instance, if a CCA has accrued reserves in 2022 when the PCIA is low, and the anticipated PCIA rate increase comes to fruition in 2023, the CCA can use those reserves to reduce customers' "at-market" generation rates for 2023, thereby keeping customers' total generation rates stable. This can be seen in the green boxes in Figure 3 below:

Figure 3



In this example, the CCA builds reserves in 2022 (the solid green box) and then uses those reserves in 2023 (dotted green box) to meet part of its obligations to energy suppliers, allowing it to keep its generation rate at 10.9 cents in 2023. Without reserves, rates would move from 11.6 cents in 2021 to 10.2 cents in 2022 and back to 11.6 cents in 2023. The result is a smoother transition from 2021 rates to 2023 rates, as can be seen below in Figure 4:

Figure 4



The result buffers the impact of swings in PCIA rates from the customer's perspective. The IOU still receives the full PCIA, with the CCAs reserves covering a portion of the other non-PCIA generation costs incurred to serve the customer.

The CCAs' use of reserves to buffer swings in generation rates is similar to the IOU balancing accounts. For instance, if the actual generation or PCIA revenues differ from the incurred costs over the course of the year the difference is reconciled and returned to, or collected from, customers over the following year. By annually reconciling forecasted and actual revenues and costs, the balancing account buffers rate volatility—absorbing periods of significant swings in generation-related costs and revenues.

In order for the CCAs to effectively use reserves to protect their customers, however, they must have the opportunity to forecast rates at an early stage, anticipate increases in PCIA rates, and plan accordingly—building reserves where necessary. To this end, CCAs require more than the publicly available monthly report data because that data does not provide the granularity necessary to accurately model changes in the PCIA.

d) Publicly available data is not sufficient to allow CCAs to plan for rate spikes in the PCIA.

The forward financial planning that is critical for an LSE—whether an IOU or CCA—to be able to financially address rate spikes requires data allowing the LSE to reasonably predict those spikes. More specifically, in order to protect customers, an LSE would need to understand:

1. PABA balances;
2. The drivers of those balances;
3. The degree to which each of those drivers is pushing the PCIA up or down for a given IOU in a given forecast year; and
4. Whether those future balances are likely to self-correct or whether corrections are unlikely.

Of these items, CCAs can only determine the first data point (current balances) using public data. IOUs on the other hand have the data necessary to determine all four data points at all times.

The below excerpt (Figure 5) from the public version of SCE's November 2020 monthly PABA report illustrates that the publicly available report does not display volumetric data (*i.e.*, kWh, MWh and MW) underlying collected IOU customer revenues, generation revenues, and RPS energy and RA capacity sales (data that is *solely* in the IOUs' possession). Instead, the report consists of two lines of data: total revenue and total costs. Those lines include no differentiation based on products or provide any indication of the volumes influencing those revenues and costs.

Figure 5: Excerpt from Public Version of SCE's November 2020 monthly PABA Report

Southern California Edison Company
Portfolio Allocation Balancing Account (PABA)
November 2020
Recorded ($000)

DESCRIPTION	January	February	March	April	May	June	July	August	September	October	November	December	Total
Beginning Balance	538,526	522,393	558,315	599,910	671,408	673,118	744,027	769,114	673,318	685,573	606,527	-	538,526
Total Net Revenues	(67,016)	(40,506)	(57,453)	(64,156)	(146,148)	(168,389)	(246,678)	(192,655)	(167,168)	(168,058)	(70,374)	-	(1,388,601)
Total PABA Costs	72,759	81,591	98,295	134,892	147,310	239,496	244,790	96,320	179,354	88,947	48,582	-	781,384
Total PABA Activity	-	-	-	-	-	-	-	-	-	-	-	-	-
Interest	767	715	752	762	549	165	115	84	68	65	55	-	4,097
Total PABA Ending Balance	545,037	564,193	599,910	671,408	673,118	744,027	769,114	673,318	685,573	606,527	584,790	-	584,790

As a result, it is impossible to discern *why* the PABA balance moved in the direction it did—*i.e.*, whether the PABA balance went up due to decreased retail sales, costs that were higher than expected, CAISO revenues that were down compared to the forecast, or even an accounting error. Summary-level historical balances provide no indication of the underlying fundamentals causing those balances, or the direction in which the balances might head in the future.

e) CalCCA's transparency proposal would provide CCAs the data they need to predict and address PCIA rate spikes.

In order to understand the drivers of PABA balances, and how much each of those drivers impacts the PCIA for a given IOU in a given forecast year (data points two and three from the list of data that an LSE requires in order to protect its customers, above), CCAs' RRs require both the confidential data underlying the monthly reports and the forecast data from the prior year's ERRA Forecast proceeding. CalCCA's transparency proposal, which would provide the CCAs reviewing representatives year-round access to the data underlying the PCIA for forecasting purposes, would allow CCAs to understand the drivers of PABA balances and the impacts of those drivers on the PCIA.

Again, the IOUs' large PCIA rate decreases forecasted in 2022 provide a helpful illustration of the importance of, and need for, confidential data. In order for an IOU or CCA to conclude that the large PCIA *decreases* from 2022 are likely to turn into large PCIA *increases* in 2023, the LSE would need insight into the drivers underlying the PCIA, including the volumetric data underlying PABA balances. In recent years, factors driving PABA balances have included demand spikes from summer heat waves, reduced customer revenues from the COVID epidemic, changes in the market value of non-RPS energy, and increases in portfolio costs. Any one of these or other factors can drive balances in different directions from year to year, and sometimes they can work in concert or in opposition to move rates within the same year.[7] In short, total balances simply do not tell a story that the CCAs can, or should be required to, plan around.

While recent advancements in transparency in ERRA Forecast proceedings have allowed LSEs to keep tabs on components moving the PABA balance, those advancements only shed light on five or six months of the year. In PG&E's 2022 ERRA Forecast proceeding, for example, PG&E's public filings indicated that the 2022 PCIA would decrease largely due to increases in the benchmark for brown power prices.[8] A decrease in that same factor may cause 2023 PCIA rates to come roaring back, but other factors (*e.g.*, a new COVID variant, persistent drought, lower than expected winter temperatures, Q4 market conditions) may mitigate or exacerbate the impact of brown power prices. While the CCAs might anticipate brown power prices decreasing (and therefore plan for anticipated increases in 2023 PCIA rates), they would have no insight into how those other factors might mitigate the impacts of lower brown power prices until June 2022, when the IOUs' 2023 ERRA Forecast proceedings begin.

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7 In PG&E's 2020 ERRA Forecast application, for example, PG&E predicted a $447.3 million undercollection in the 2019 PABA until the day before hearing when a $224 million error related to the imputed RA value was discovered. The resulting modification changed the projected $447.3 million undercollection to a $223.5 million undercollection. Three months later, however, PG&E's 2019 PABA undercollection grew almost $400 million to reach $611.4 million. These fluctuations had an enormous impact on the rates CCA customers would pay, moving the PCIA by approximately $0.005/kWh (or 15 percent) in three months. *See* R.17-06-026, Comments of CalCCA on Data-Related PCIA Issues at 9 (Oct. 1, 2021).

8 *See* Attachment A (Table D in PG&E November Update).

That opacity matters. For example, PG&E recorded a $*145M undercollection* in the PABA for Q4 of 2020.[9] This undercollection occurred after PG&E's 2021 ERRA forecast proceeding had closed, which means it occurred after PG&E had stopped providing the confidential information underlying that undercollection to the CCAs. As a result, there was no way for the CCAs to analyze the drivers of the resulting change in the PABA balance that PG&E reported publicly in late Q4 of 2020 until the ERRA Forecast proceeding began in June of 2021. The CCAs essentially lost more than six months of time that could have been used to prepare and plan for rate changes for their customers.

In contrast, PG&E knew those drivers—lower customer revenues and lower CAISO revenues, offset by an ERRA overcollection transferred to PABA—*half a year earlier* and could plan and act on them on behalf of bundled customers, while unbundled customers were left more exposed. The Commission should not allow this stark disparity between bundled and unbundled customers, and their respective LSEs' ability to plan on their behalf, to persist.

In addition to understanding the drivers of PABA balances, understanding how much each of those drivers impacts the PCIA for a given IOU in a given forecast year is also critical. That is because a utility portfolio's values and costs will shift from one year to the next. If, for example, the drivers reveal that a deep drought is affecting utility-owned hydro resources, an analyst needs to know how much energy the utility forecasted hydro resources would generate, *i.e.*, how much those resources impact the PCIA. These data are included in the prior year's forecast workpapers.[10] Without those workpapers, an analyst cannot translate a particular driver into an impact on the PCIA. In order to do that, an analyst needs to know, for example, the

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9 A.21-06-001, Exh. PGE-5 at 18 (Nov. 8, 2021).

10 To be clear, the CCAs do not require on-going access to production cost modeling, dispatch models or load forecasts. All of those confidential inputs inform the forecast workpapers but only their outputs, included in the workpapers, are necessary here.

normal output from those resources and the hydro facilities that the utility forecasted as being in the resource mix the following year.

The CCAs only seek the same tools the utilities have, and those tools can be gleaned from workpapers already provided as part of the ERRA forecast case. The incremental change the CCAs require is to be able to use those workpapers outside of those cases to help forecast PCIA rates. Once the CCAs know the drivers of PABA balances, and the CCAs have the ability to use prior years' forecasts workpapers, the CCAs will be in the same position as the IOUs with respect to their ability to plan for changes in PCIA rates for their customers.

CalCCA notes that there is a further step to protecting customers beyond knowing the drivers and the impact those drivers will have: what will happen to those drivers for the rest of the year and, as a result, whether future balances are likely to self-correct or whether corrections are unlikely. That part of the analysis, *e.g.*, the direction a particular driver may move over the course of the year, such as the price of non-RPS energy, is outside the scope of CalCCA's proposal. Individual LSEs will need to rely on their own market forecasting to determine where a factor like non-RPS energy prices may go.

However, that analysis cannot be carried out if one does not know the market drivers in the first place, *i.e.*, which market factors matter most in a particular year. Once those drivers are known, an LSE can assess general market trends and consider whether those drivers are likely to lead to the balances correcting themselves or worsening over the rest of the year, whether those trends will continue in the future, and how those trends will impact future indifference amounts. Again, leaning on the example of decreasing 2022 PCIA rates: a CCA may come to realize that any gain from a reduced PCIA in 2022 should be put into reserves to protect against a 2023 rate spike. Or, the CCA may learn that other factors such as higher-than-forecast customer demand are offsetting the effects of lower-than-forecast brown power prices and therefore such reserves are not necessary for 2023.

These factors inform the basis of ALJ Wang's requested "analysis of the impact of having more accurate estimates (rather than less accurate estimates based on public data) on a CCA's or Direct Access provider's ability to protect customers from rate spikes during each quarter of the year"[11]. The impact of having more accurate estimates (rather than less accurate estimates based on public data) is directly tied the size of the potential PCIA rate swings in coming years and how long LSE have to prepare for them. In other words, the more sharply the PCIA rate rises or drops, the greater the value of more accurate estimates, because the incremental accuracy better informs planning for the sharp rise or drop in the PCIA.

In the past few years, PABA balances have swung by hundreds of millions of dollars. In 2021 alone, an update to the brown power benchmark added nearly $1.5 billion of value to PG&E's portfolio. Therefore, if a CCA has *zero* idea of factors driving the PABA balance until confidential workpapers are provided as part of the ERRA Forecast cases in June, the value of data could easily reach hundreds of millions of dollars in impacts to unbundled customers.

Question 2. Reviewing Representatives Need Only to Disclose the Same Information Utilities Include in Public ERRA Forecast Pleadings.

What specific information should reviewing representatives, under a nondisclosure agreement, be allowed to disclose to CCAs or Direct Access providers for the purpose of developing or understanding PCIA or PABA rate forecasts?

Please explain (a) why this specific information is necessary for the intended purpose, (b) how this information will be used to develop or understand PCIA or PABA rate forecasts, and (c) what are the risks

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[11] E-mail Ruling Requesting Comments on PCIA Forecasting Data Access at 4 (Nov. 5, 2021).

associated with disclosure of this specific information by reviewing representatives to CCAs or Direct Access providers.

a) Reviewing representatives need only to disclose summary level revenue requirements, forecasted PCIA rates, and the drivers underlying those rates to the CCAs.

In order for CCAs to take timely, meaningful action to protect their customers from rate volatility, RRs only need to disclose summary level revenue requirements, forecasted PCIA rates, and, importantly, the *drivers* underlying those rates to the CCAs. The IOUs already disclose this aggregated (not resource-specific) information in public filings made in ERRA Forecast proceedings, and therefore, as these comments explain in more detail in response to subpart (c) below, disclosure of this information creates no incremental risks. Summary level revenue requirements, forecasted PCIA rates, and the drivers underlying those rates are necessary in order for the CCAs to know which elements of the market are affecting PABA balances, and in turn plan to use their reserves if necessary to protect their customers from large customers in their total generation rates.

b) How will this information be used to develop or understand PCIA or PABA rate forecasts?

This question is answered in detail in response to Question 1 above: Once PABA drivers are known, an LSE can assess general market trends and consider whether those drivers are likely to lead to the balances correcting themselves or worsening over the rest of the year, whether those trends will continue in the future, and how those trends will impact future indifference amounts.

c) There are no incremental risks associated with disclosure of these data.

The CCAs transparency proposal does not present any incremental risks to the disclosure of confidential information. That is fundamentally because the CCAs' RRs seek to disclose the *same* type of aggregated information that the IOUs currently disclose as public filings within ERRA Forecast proceedings. Rather than remaining in the dark for half of the year, and waiting for the IOUs to make public filings as a part of their ERRA Forecast proceedings, under CalCCA's proposal, the CCAs' RRs would have access to the data underlying the PCIA year--round.

The attachments to this filing show that the IOUs' public filings in their ERRA Forecast cases disclose summary level revenue requirements, forecasted PCIA rates, and the drivers underlying those rates—the very information that the CCAs require to plan for their customers. Attachments A and B show the drivers and analysis that the IOUs provided in their November Updates. Attachment C is an example of an IOU showing the PCIA rate they forecast in June, and then update in November, that will be implemented on January 1 of the following year.

The terms of the NDA currently used in ERRA Forecast proceedings largely address the specific information a RR can disclose, *i.e.*, information that has not been properly marked as "Protected Materials Subject to Nondisclosure Agreement." CalCCA proposes a year-round NDA that would require RRs to follow a similarly rigorous process to the one they follow in an ERRA Forecast case. This includes putting in place and following protocols required by D.11-07-028, including an ethics wall incorporating the following standards:

- When reviewing or discussing any market sensitive data, the Reviewing Representative and those working with them shall employ all reasonable steps to ensure a physical separation from firm personnel who are not authorized Reviewing Representatives;
- The Reviewing Representative shall be responsible for informing all firm personnel about the existence and terms of the Commission's confidentiality rules, and in particular the prohibition against sharing market sensitive information with Market Participants; and
- The Reviewing Representative shall take all reasonable steps necessary to ensure that market sensitive information and files, including electronic files, are not accessible to firm personnel who are not authorized Reviewing Representatives.

The CCAs RRs are closely familiar with these standards, and have experience implementing these protections due to their experience with ERRA proceedings. Personnel at NewGen Strategies and Solutions, LLC and Keyes & Fox LLP, for example, that are RRs on behalf of the CCAs, have all been trained on the D.11-07-028 criteria, including the fact that when reviewing or discussing market sensitive data, reasonable measures should be taken to physically separate from non-CCA RRs. Moreover, CCA RRs either work remotely or have access to enclosed offices and meeting rooms where sensitive information may be discussed. CCA RRs review the D.11-07-028 standards with their colleagues periodically in regularly-scheduled practice-wide conference calls. Further, the CCA RRs have established secure electronic file storage locations with restricted access; permission to access file storage locations must be affirmatively granted to current NDA signatories. Each of these protocols would continue with regard to any data provided under the year-round NDA that CalCCA's proposal contemplates.

Under CalCCA's proposal, RRs would sign an NDA including the following protections:

- IOUs' ability to challenge a RR and refuse to disclose data to particular individuals the IOUs do not believe qualify as RRs;
- Limitations on the use of data, modified in a manner such as the following: "Reviewing Representatives shall use Protected Materials solely for the purpose of participating in this proceeding and more generally for use in PCIA forecasting, on behalf of Market Participants and Non-Market Participants, provided that any confidential data remains protected from disclosure within the forecasting model and subject to the ongoing conditions of the NDA.";
- Proper marking of documents, *e.g.*, designation of "protected materials" and redaction of confidential data where appropriate;
- Limitations on the ability to make copies of protected materials;
- Liability for unauthorized disclosure;
- Notice provisions regarding requests to disclose protected materials; and
- One-year terms, such that RRs are required to execute a new NDA each year in order to gain or continue to have access to protected materials, which would allow

IOUs to re-evaluate RRs on an annual basis, including the ability to require the RRs to destroy materials once a person is no longer a RR.

Under the terms of that NDA, CCA RRs would receive confidential data and analyze that data. They would then aggregate that confidential data such that they ultimately disclose, to the CCAs, the same type of analysis provided by the IOUs in public testimony in ERRA Forecast proceedings.

A couple key aspects of CalCCA's proposal bear emphasis. First: no personnel of a market participant will ever have access to confidential procurement information as a result of CalCCA's proposal. The proposal works within the Commission's existing confidentiality framework, which only gives qualified reviewing representatives access to confidential information.[12] Second: there is almost zero potential for a model showing a range of $/kWh PCIA rates to influence the market price of energy or capacity. The model would present a range of possible PCIA rates based on possible market outcomes that an individual user selects, *e.g.*, if brown power prices are *x*, and retails sales are *y*, then the PCIA would be *z*. This modeling cannot influence the clearing price of a particular Request for Offer or the contract price of a bilateral transaction because it is not possible to discern the price an IOU or another load-serving entity (LSE) is willing to pay for capacity or energy from a $/kWh PCIA forecast—the modeling results are simply too aggregated.

The IOUs' own ERRA Forecast applications, workpapers and testimony demonstrate this fact. In those cases, the forecasted PCIA rates the IOUs propose rely on a great deal of market-sensitive information, but none of the proposed revenue requirements or forecasted PCIA rates are redacted in those pleadings, as shown in Attachments A-C to these comments. The reason why none of those revenue requirements or forecasted rates are redacted is that the outputs are

[12] CalCCA Opening Comments at 19-22.

too aggregated to be of any value to an unscrupulous party looking to manipulate the market. CalCCA's proposal therefore builds upon a confidentiality framework that has protected utility data for nearly 20 years and presents no incremental risk.

Question 3. Planning Requires Understanding the Drivers Causing PCIA Rate Movements.

The ALJ Ruling states:

Should the Commission mitigate the risks of PCIA data access by only allowing reviewing representatives to disclose to CCAs or Direct Access providers the reviewing representative's estimated PCIA and PABA forecasts, without disclosing any information about the underlying data or drivers of these forecasts?

(a) Would this information be sufficient to enable CCAs or Direct Access providers to prevent rate spikes for customers?

(b) Are there any risks associated with reviewing representatives disclosing solely their PCIA and PABA forecast estimates to CCAs or Direct Access providers?

a) Disclosing estimated PCIA and PABA forecasts, without disclosing any information about the underlying data or drivers of those forecasts, would not be sufficient to enable CCAs to prevent rate spikes.

As these comments discuss in length in response to the ALJ's Question 1, the CCAs must understand the drivers of PCIA and PABA forecasts in order to understand what is causing any increase in those forecasts. Without the drivers, the information would not be sufficient to enable CCAs to prevent rate spikes for customers.

In 2020, for instance, each utility's PABA balance rose sharply by mid-year due to decreased customer revenues from the COVID epidemic, a drop in the market value of non-RPS energy and RPS energy, and, to a lesser extent, lower RA value and an increase in portfolio costs. By the end of the year, each utility's PABA balance had dropped significantly due to high brown power prices caused by late-summer heat waves. Prudent LSEs must keep tabs on these individual components—rather than considering only their aggregated impact on PABA balances—in order to plan in the short term for PCIA changes occurring on January 1. Understanding PABA drivers year-round allows CCAs to know which specific elements of the market are affecting PABA balances every month of the year. Volumetric data (*i.e.*, kWh, MWh and MW) underlying collected IOU customer revenues, generation revenues, and RPS energy and RA capacity sales illuminate not only which way the PABA balance is moving but most importantly *why* it is moving in that direction.

The Commission should therefore not require *solely* the disclosure of estimated PCIA and PABA forecasts, without disclosure of the granular data necessary to discern the underlying drivers of those forecasts.

b) There is no incremental risk associated with reviewing representatives disclosing data the IOUs already disclose within ERRA forecast proceedings.

As discussed in response to Question 2, both the IOUs and CCA Reviewing Representatives each year provide public testimony to the Commission that includes PCIA and PABA Forecast estimates. There is no incremental risk associated with CCAs' RRs disclosing this information to the CCAs in the same manner it is disclosed publicly in the ERRA forecast proceedings. No party could use this aggregated information to inform a bid price in a request for offers or a bilateral negotiation.

III. MEET AND CONFER WITH SCE: AN UPDATE ON CONFIDENTIAL DATA CONSISTENCY AMONG IOUS

In the Joint IOUs' October 8, 2021 reply comments,[13] SCE committed to meet and confer with the CalCCA regarding the confidential treatment of data CalCCA feels should be made

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[13] R.17-06-026, *Joint Reply of Southern California Edison Company (U 338-E), Pacific Gas and Electric Company (U 39-E) and San Diego Gas & Electric Company (U 902-E) to Administrative Law Judge's Ruling Requesting Comments on ERRA-Related PCIA Issues*, at 14-15 (Oct. 8, 2021).

public. That meet-and-confer took place on November 2, 2021, and was productive, with SCE committing to making certain data in Tables 1 and 2 from CalCCA's Opening Comments public. CalCCA hopes to be able to provide further details on the progress made in those discussions in reply comments.

IV. CONCLUSION

As these comments and CalCCA's previously-filed comments in this proceeding describe, the Commission's existing data access protocols are in urgent need of reform to increase transparency related to the balancing accounts that underlie PCIA rates. CalCCA therefore respectfully requests that the Commission authorize an NDA that provides CCAs' RRs (and the RRs of other entities with customers who pay the PCIA) access to the following data year-round:

- The confidential versions of the IOUs' Monthly Reports for each month of the year at the same time such confidential versions are provided to the Commission;
- The data and workpapers underlying those Monthly Reports, at the same level of granularity and within the same schedule, that is now required to be provided as part of ERRA Forecast proceedings in each IOU service territory; and
- The workpapers underlying PCIA rates that the IOUs have provided within the prior year's ERRA Forecast proceedings as part of either the November Update or an advice letter implementing the final decision in the ERRA Forecast proceeding.

Respectfully submitted,

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On behalf of
California Community Choice Association

December 9, 2021

ATTACHMENT A

TABLE D
PRIMARY DRIVERS FOR PABA OVERCOLLECTION SUMMARY
(MILLIONS OF DOLLARS)

Line No.	Description		Approximate Impact (Over)/ Under Collection
1	Increase in Expected Net California Independent System Operator (CAISO) Revenues		
	(a) Higher Market Electricity Prices	$(1,050)	
	(b) Less Generation from PCIA-Eligible Resources	330	
	Subtotal		$(720)
2	Higher Procurement Cost		
	(a) Higher Fuel Costs for Natural Gas-fired Generators	$110	
	(b) Lower Capacity Costs Driven by Unplanned Outage	(95)	
	(c) RPS Contract Procurement Costs	85	
	Subtotal		$(100)
3	Higher Recorded Undercollection Brought Forward From 2020		
	(a) Lower-Than-Expected Recorded Customer Revenues	$125	
	(b) Net Impact from Lower Recorded CAISO Revenues and Lower Procurement Costs	50	
	(c) Greater-Than-Expected ERRA Overcollection Transferred to PABA	(30)	
	Subtotal		$145
4	Authorized 2021 RTBA-E Balances in D.20-12-005		$153
5	Higher Customer Revenue		$(75)
6	RA Market Value		
	(a) 2021 Final RA Adder	$(50)	
	(b) PCIA Template Line Loss Issue	35	
	Subtotal		$ (15)
7	RPS Market Value		
	(a) 2021 Final RPS Adder	$5	
	(b) Lower RPS Sales	(10)	
	Subtotal		$(5)
8	Recorded One-Time Adjustments		
	(a) Recorded One-Time Adjustments discussed in PG&E's June Prepared and August Revised Testimony		
	(1) Cumulative Authorized Balancing Account Transfers(a)	$(41)	
	(2) Updated 2020 RTBA-E Transfers	35	
	(3) Adjustments to Pension Revenue Requirement and donations of hydro facilities	(24)	
	(b) One-Time Adjustments recorded in May through September		
	(1) 2019 Diablo Canyon Seismic Studies Balancing Account (DCSSBA) and 2020 Wildfire Mitigation Balancing Account (WMBA) Transfers	6	
	(2) Loss on Chili Bar Hydro Sale	10	
9	Other		$(20)
10	Forecast 2021 Year-End PABA balance, Prior to Transfer from ERRA-Main		$(451)

(a) The balancing accounts to and from PABA are Diablo Canyon Retirement Balancing Account (DCRBA), Department of Litigation Balancing Account (DOELBA), Land Conservation Plan Environmental Remediation Memo Account (LCPERMA), Nuclear Regulatory Commission Rulemaking Balancing Account (NRCRBA), and Disadvantage Community Green Tariff (DAC-GT) Balancing Account

1) Increase in Expected Net CAISO Revenues

a) Higher Market Electricity Prices

Average 2021 CAISO market electricity prices are expected to be more than 50 percent greater than the forecast 2021 Energy Benchmark (brown power), resulting in additional CAISO revenues of approximately $1 billion. The increase in CAISO electricity prices is driven primarily by higher than expected natural gas prices, which were approximately 20 percent greater than the 2021 PG&E Citygate forward prices adopted in D.20-12-038 through September, and are expected to be almost double for October through December.

b) Less Generation From PCIA-eligible Resources

Increased revenues from higher market prices are offset, in part, by a reduction in expected total generation. Generation from PCIA-eligible resources is expected to be approximately 8,200 gigawatt hour (GWh) less than the authorized 2021 forecast driven primarily by low precipitation and snowpack. This reduction in generation represents an approximately $330 million decrease in CAISO market revenues compared to forecast. The net impact is an approximately $720 million increase in CAISO revenues.

2) Higher Procurement Costs

a) Higher Fuel Costs for Natural Gas-fired Generators

Fuel costs from natural gas-fired resources in PG&E's electric portfolio are expected to be approximately $110 million higher, primarily due to higher natural gas prices. PG&E Citygate natural gas prices for 2021 are projected to be approximately 40 percent higher than the 2021 forward prices adopted in D.20-12-038, driven by both nine months of recorded and the balance three months of forecast higher gas prices.[22]

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[22] The three months of gas prices from October through December 2021 are forecast based on September 20, 2021 forward prices.

b) Lower Capacity Costs Driven by Unplanned Outage

Due to generator outage issues at a third-party generating facility that began in May 2021, capacity costs are expected to be approximately $95 million lower.

c) Higher RPS Contract Procurement Costs

Procurement costs from RPS-eligible contracts are approximately $85 million greater due to: (1) higher CAISO market electricity prices for contracts with index-based pricing; (2) greater generation from variable priced wind resources; and (3) lower-than-expected RPS sales.

3) Higher Recorded Undercollection Brought Forward From 2020

The recorded PABA undercollection brought forward from 2020 was $145 million higher than forecasted in 2021 rates, driven by the difference between forecast and actuals for October through December 2020. This was primarily due to lower-than-expected recorded customer billed revenues of $125 million, as well as lower recorded CAISO revenues for PCIA-eligible resources that were partially offset by lower procurement costs, resulting in an additional net undercollection of $50 million. This $175 million undercollection was partially offset by a greater-than-expected recorded ERRA overcollection of $30 million that was transferred to PABA.

4) Authorized Recovery of the Forecasted 2021 Risk Transfer Balancing Account Balances in D.20-12-005

The forecast year-end balance in the Electric Risk Transfer Balancing Account (RTBA-E) is $162 million, comprising of (a) the Third-Party Generation Subaccount of $152 million and (b) the electric generation portion of the Additional Coverage Subaccount of $10 million.

The Additional Coverage Subaccount tracks the cost to purchase of more than $1.4 billion in financial risk total coverage authorized in D.20-12-005 and is allocated to the electric distribution and generation functions. PG&E's Electric Preliminary Statement Part IN stated that the costs recorded to this subaccount is authorized for recovery upon the approval of a Tier 2 Advice Letter. On July 8, 2021, the Commission approved PG&E's AL 4444-G/6210-E to recover the cost of excess liability insurance above $1.4 billion in coverage obtained by PG&E in 2020.[23]

Based on the same allocation methodology presented in PG&E's September Supplement, $153 million of the 2021 RTBA balance is to be recovered in PABA and the balance of $9 million in ERRA.

5) Higher Customer Revenue

PCIA customer revenues are approximately $75 million higher than the PCIA revenue requirement authorized in D.20-12-038. This increase is primarily due to a difference in the sales forecast authorized in D.20-12-038, with regards to recorded sales mix of PCIA customer classes, as well as approximately two percent higher than the forecast PCIA customer usage, among other things, resulting in an over-collection of PCIA revenues.

6) RA Market Value

a) 2021 Final RA Adder

Pursuant to D.19-10-001, PG&E updated the RA Market Value to be calculated based on the Final RA Adders provided by Commission on November 1, 2021. The Final RA Adders were on average higher than the Forecast RA Adders authorized in D.20-12-038.[24] This resulted in an over-collection of retained RA value of approximately $50 million.

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23 PG&E did not include the related cost approved in Advice 4444-G/6210-E and recorded in the Additional Coverage Subaccount of the RTBA in the September Supplement because certain information was unavailable at that time. PG&E's November Update contains updated information concerning: (a) the accelerated expense recognition in the September business close due to exhaustion of coverage (results in higher cost subject to recovery), and (b) the adjustment of costs allocated between within and above $1.4 billion coverage.

24 Compared to the Forecast RA Adders authorized in D.20-12-038, the change per kW-year of the RA Adders are: (1) increases in System $14.76; (2) increase in PG&E Local $1.92; (3) increase in SCE Local $1.08; and (4) decrease in Flex $3.60.

b) **PCIA Template Line Loss Issue**

The CPUC-mandated PCIA template used to calculate the D.20-12-038 authorized PCIA revenue requirement includes a formula error that inadvertently overstates the quantity of RA supply by multiplying it by a six percent line loss factor. This overstatement of forecasted retained RA volume resulted in an approximately $35 million undercollection in PABA.[25]

7) **RPS Market Value**

a) **2021 Final RPS Adder**

Pursuant to D.19-10-001, PG&E updated the imputed RPS market value based on the Final RPS Adder provided by Commission on November 1, 2021. The Final RPS Adder was $0.26 per MWh lower than the Forecast RPS Adder authorized in D.20-12-038. This resulted in an undercollection in retained Renewable Energy Credit (REC) value of approximately $5 million.

b) **Lower RPS Sales**

Based on the additional RPS sales solicitations PG&E held after the 2021 ERRA Forecast's November Update, PG&E forecasts it will sell approximately 800 GWh less RPS-eligible energy than was assumed in the authorized D.20-12-038 PCIA forecast. The decrease in RPS sales increased both the imputed REC market value, as noted above, by approximately $10 million.[26]

c) **Unsold RPS**

Pursuant to D.20-02-047, PG&E is not including actual Unsold RPS for 2021 as a tracking framework within PABA has yet to be developed in the PCIA proceeding to determine

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[25] This issue is addressed in D.21-03-051, whereby the six percent line loss factor calculation error is authorized to be removed from the D.17-08-026 workpaper template for calculating the 2022 PCIA revenue requirement presented in this testimony.

[26] Lower RPS sales increase the total imputed REC market value based on the RPS adder and have an offsetting increase to the total portfolio costs.

'whether retired RECs in PABA were "unsold" or "retained for compliance."'

8) Recorded One-Time Adjustments

a) Recorded One-Time Adjustments Discussed in PG&E's Revised Testimony

1) Cumulative credit of $41 million for the transfers of balances from the DCRBA, DOELBA, LCPERMA, NRCRBA, and DAC-GT Balancing Account, as discussed in PG&E's Revised Testimony;[27]
2) Updated debit of $35 million for the transfer of the recorded 2020 RTBA-E balance authorized in D.20-12-005;[28] and
3) Credit of $23 million for lower 2020 Pension Revenue Requirement;[29] and $354,000 related to the donations for PG&E's facilities at Lake Almanor, Lake Britton, and Lake Spaulding.[30]

b) One-Time Adjustments Recorded in May through September 2021, Updated in This Updated Testimony

1) Debits of $4 million and $2 million, respectively, for the transfer of the 2019 DCSSBA balance authorized in D.21-07-013; and the 2020 WMBA balance approved in AL 4392-G/6100-E; and
2) Debit of $10 million for the loss on sale of PG&E's Chili Bar Hydro facility. The Commission approved the sale and ratemaking treatment in D.20-11-024. In accordance with OP 3, within 60 days of the closing of the sale on June 16, 2021, PG&E submitted AL 6296-E with its final financial and tax information.

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[27] Exhibit PGE-1, p. 15-12, line 19 through p. 15-13, line 10 and lines 20 through 27.

[28] Exhibit PGE-1, p. 15-13, line 14 stated a debit of $37 million recorded to PABA. In August Accounting close, PG&E recorded a $2 million credit, resulting in an updated 2020 balance debit of $35 million.

[29] Exhibit PGE-1, p. 15-13, lines 15 through 19.

[30] Exhibit PGE-1, p. 15-13, line 28 through p. 15-14, line 6.

ATTACHMENT B

Table X-49
Comparison of 2021 Forecast MPBs to 2021 Final MBPs

Market Price Benchmark (MPB)	2021 Forecast Adders June 2021	2021 Final Adders November 2021	% Change
Energy Index	$40.59/MWh	N/A (use actuals)	N/A
RPS Adder	14.49/MWh	$14.23/MWh	*-1.79%*
RA Adders			
System	$73.20/kW-yr	$87.96/kW-yr	*20.16%*
Local	$76.44/kW-yr	$77.52/kW-yr	*1.41%*
Flex	$68.28/kW-yr	$64.68/kW-yr	*-5.27%*

D. <u>2021 PABA Year-End Balance and Variance Analysis</u>

The PABA records the difference between actual above-market costs and actual customer revenues. Actual costs, market revenues and imputed revenues are recorded to the PABA based on the operation of the resources in SCE's PABA portfolio. Billed revenues received from customers (*i.e.,* the product of actual kWh by the approved ERRA Forecast rates) are recorded to the PABA based on actual customer usage. When the actual above-market costs exceed the actual billed customer revenues, an undercollection results. Alternatively, if the actual above-market costs are less than the actual billed customer revenues, the PABA will show an overcollection.

Table X-50 shows the forecast year-end balance in the PABA for 2021, by vintage, using the updated inputs described herein. January through September are based on recorded actuals, while October through December remain based on a forecast.

Table X-50
Updated Forecast 2021 Year-End PABA Balance by Vintage

Line No		Vintage CTC	One-Time Refunds	Legacy UOG	Vin 2004-2009	Vin 2010	Vin 2011	Vin 2012	Vin 2013	Vin 2014	Vin 2015	Vin 2016	Vin 2017	Vin 2018	Vin 2019	Vin 2020	Vin 2021	Total
1	Recorded Balances from January to September 2021 (a)																	
2	Billed Customer Revenues	(2,918)	(8,389)	(151,117)	(508,932)	(172,204)	(227,758)	(29,781)	(91,129)	(149,833)	(84,657)	109,965	(6,983)	(15,996)	27,458	77,651	0	(1,234,623)
3	Portfolio Costs	23,224	0	448,552	894,362	257,620	319,057	63,498	57,011	272,517	287,357	30,520	748	12,169	185,040	195,725	0	3,047,400
	Common & Indiret Costs	3	0	3	49	18	23	6	5	33	52	5	0	2	0	0	0	200
4	Energy Value	(14,488)	0	(258,643)	(268,961)	(77,471)	(96,096)	(23,920)	(24,106)	(84,359)	(176,932)	(39,887)	(781)	(8,487)	(77,402)	0	0	(1,151,533)
5	RPS Value	(5,209)	0	(4,057)	(76,105)	(28,424)	(36,430)	(8,620)	(8,654)	(53,372)	(85,506)	(8,024)	(282)	(3,020)	0	0	0	(317,703)
6	RA Value	(2,958)	0	(75,073)	(69,886)	(10,971)	(11,269)	(1,439)	(2,368)	(21,689)	(23,997)	(9,718)	(60)	(977)	(105,192)	(200,565)	0	(536,162)
7	Other Resource Revenue	0	0	0	(40,798)	0	0	0	0	0	0	0	0	0	0	0	0	(40,798)
8	One-Time Adjustments	0	8,343	(7,231)	(3,121)	(70)	(95)	(12)	(40)	(64)	(36)	450	(3)	(8)	1,789	(147,958)	0	(148,057)
9	Interest	(6)	9	37	24	18	35	(3)	38	67	56	(47)	5	11	(5)	(101)	0	140
10	Recorded Balances from January to September 2021 (a)	(2,352)	(37)	(47,530)	(73,369)	(31,484)	(52,532)	(271)	(69,243)	(36,698)	(83,663)	83,264	(7,356)	(16,305)	31,688	(75,247)	0	(381,136)
11	Forecast from October to December 2021 (b)																	
12	Billed Customer Revenues	(645)	(1,854)	(33,393)	(112,461)	(38,053)	(50,328)	(6,581)	(20,137)	(33,109)	(18,707)	24,299	(1,543)	(3,535)	6,068	17,159	0	(272,819)
13	Portfolio Costs	5,152	0	129,680	221,459	57,150	70,779	14,086	12,647	60,454	63,746	6,770	166	2,700	41,049	43,419	0	729,256
	Common & Indirect Costs	0	30	581	215	269	65	64	394	609	59	2	22	0	0	0	0	2,309
14	Energy Value	(1,737)	0	(31,018)	(32,256)	(9,291)	(11,524)	(2,869)	(2,891)	(10,117)	(21,219)	(4,783)	(94)	(1,018)	(9,283)	0	0	(138,099)
15	RPS Value	(1,187)	0	(924)	(17,284)	(6,452)	(8,292)	(1,958)	(1,971)	(12,147)	(19,829)	(1,835)	(64)	(690)	0	0	0	(72,633)
16	RA Value	(772)	0	(21,135)	(20,048)	(2,891)	(2,978)	(378)	(634)	(5,687)	(6,333)	(2,536)	(17)	(257)	(28,246)	(56,905)	0	(148,817)
17	Other Resource Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	One-Time Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Interest	(1)	1	5	3	3	5	(0)	5	9	8	(6)	1	1	(1)	(14)	0	19
	RPS True-Up Entry	83	0	67	1,279	469	576	142	139	855	1,267	130	4	47	0	0	0	5,058
	RA True-Up Entry	(499)	0	(10,181)	(11,923)	(1,542)	(1,441)	(208)	(319)	(3,261)	(3,287)	(1,525)	(7)	(129)	(16,923)	(31,885)	(16)	(83,146)
20	Forecast Balances from October to December 2021	393	(1,822)	33,682	28,983	(338)	(3,139)	2,298	(12,766)	(2,393)	(4,295)	20,516	(1,532)	(2,880)	(7,336)	(28,226)	(16)	104,274
21	Year-End 2021 Forecast (c = a + b)																	
22	Billed Customer Revenues	(3,563)	(10,243)	(184,510)	(621,393)	(210,257)	(278,086)	(36,362)	(111,266)	(182,942)	(103,364)	134,265	(8,527)	(19,530)	33,525	94,809	0	(1,507,442)
23	Portfolio Costs	28,376	0	578,232	1,115,820	314,770	389,836	77,584	69,658	332,971	351,103	37,290	914	14,869	226,089	239,144	0	3,776,656
	Common & Indirect Costs	3	30	583	264	287	88	70	399	643	110	7	22	2	0	0	0	2,509
24	Energy Value	(16,225)	0	(289,661)	(301,217)	(86,762)	(107,621)	(26,788)	(26,997)	(94,476)	(198,150)	(44,670)	(874)	(9,505)	(86,685)	0	0	(1,289,632)
25	RPS Value	(6,397)	0	(4,980)	(93,389)	(34,877)	(44,722)	(10,577)	(10,625)	(65,519)	(105,335)	(9,859)	(346)	(3,710)	0	0	0	(390,336)
26	RA Value	(3,730)	0	(96,207)	(89,935)	(13,862)	(14,247)	(1,817)	(3,001)	(27,376)	(30,330)	(12,254)	(77)	(1,233)	(133,438)	(257,470)	0	(684,978)
27	Other Resource Revenue	0	0	0	(40,798)	0	0	0	0	0	0	0	0	0	0	0	0	(40,798)
28	One-Time Adjustments	0	8,343	(7,231)	(3,121)	(70)	(95)	(12)	(40)	(64)	(36)	450	(3)	(8)	1,789	(147,958)	0	(148,057)
29	Interest	(7)	11	42	27	21	40	(3)	44	77	64	(54)	6	12	(5)	(115)	0	160
	RPS True-Up Entry	83	0	67	1,279	469	576	142	139	855	1,267	130	4	47	0	0	0	5,058
	RA True-Up Entry	(499)	0	(10,181)	(11,923)	(1,542)	(1,441)	(208)	(319)	(3,261)	(3,287)	(1,525)	(7)	(129)	(16,923)	(31,885)	(16)	(83,130)
30	Total 2021 Activity	(1,958)	(1,859)	(13,849)	(44,386)	(31,822)	(55,671)	2,027	(82,009)	(39,092)	(87,957)	103,780	(8,888)	(19,186)	24,352	(103,474)	(16)	(359,992)
	Beginning Balance	*(7,471)*	*13,931*	*84,129*	*59,312*	*39,517*	*82,882*	*(4,135)*	*89,266*	*128,542*	*116,182*	*(111,280)*	*11,130*	*22,610*	*(29,542)*	*(59,821)*	*0*	*435,255*
	Final Balance	**(9,429)**	**12,072**	**70,281**	**14,926**	**7,695**	**27,211**	**(2,107)**	**7,257**	**89,451**	**28,225**	**(7,500)**	**2,241**	**3,425**	**(5,190)**	**(163,294)**	**(16)**	**75,247**
31	FF&U @ 0 988939	(105)	135	786	167	86	304	(24)	81	1,000	316	(84)	25	38	(58)	(1,826)	(0)	842
32	**Total Year-End Balance Forecast with FF&U**	**(9,535)**	**12,207**	**71,067**	**15,093**	**7,781**	**27,515**	**(2,131)**	**7,338**	**90,451**	**28,541**	**(7,584)**	**2,266**	**3,463**	**(5,248)**	**(165,121)**	**(16)**	**76,088**

The forecast 2021 year-end balance in the PABA is an undercollection of $75.247 million ($76.080 million including FF&U). This amount – by resource vintage – is included in the forecast 2022 PCIA revenue requirement included in Appendix B. SCE compared recorded actuals and the projected year-end balances by category to the approved 2021 forecast to determine the key drivers contributing to the forecast year-end undercollection balance in the PABA. The results are summarized in Table XI-55 and discussed in the following sections.

Table X-51
2021 YE PABA Undercollection Variance Analysis

Line No.	Category	2021 PCIA Forecast ($000)	2021 YE Projection ($000)	Variance ($000)	Variance %
1	AGBRR	$ 689,570	$ 687,307	$ (2,263)	-0.33%
2	Fuel, Contracts, Other Costs	$ 2,968,143	$ 3,093,696	$ 125,552	4.23%
3	**Total Portfolio Costs**	**$ 3,657,714**	**$ 3,781,003**	**$ 123,289**	**3.37%**
4	**Energy Value[1]**	**$ (1,506,341)**	**$ (1,289,632)**	**$ 216,709**	**-14.39%**
5	Forecast/Actual Retained RPS[2]	$ (262,049)	$ (279,133)	$ (17,084)	6.52%
6	RPS True-Up		$ 5,058	$ 5,058	100.00%
7	Forecast/Actual Sold RPS	$ (121,974)	$ (111,203)	$ 10,771	-8.83%
8	**RPS Value**	**$ (384,024)**	**$ (385,279)**	**$ (1,255)**	**0.33%**
9	Forecast/Actual Retained RA	$ (664,220)	$ (597,401)	$ 66,819	-10.06%
10	RA True-Up		$ (83,146)	$ (83,146)	-100.00%
11	Forecast/Actual Sold RA	$ (73,924)	$ (87,578)	$ (13,654)	18.47%
12	**RA Value**	**$ (738,144)**	**$ (768,124)**	**$ (29,980)**	**4.06%**
13	**Total Market Value**	**$ (2,628,508)**	**$ (2,443,035)**	**$ 185,473**	**-7.06%**
14	**Indifference Amount**	**$ 1,029,205**	**$ 1,337,968**	**$ 308,762**	**30.00%**
15	Misc Adjustments / Bilateral Sales	$ -	(190,533)		
16	**Adj PCIA Revenue Requirement**	**$ 1,029,205**	**$ 1,147,434**	**$ 118,229**	**11.49%**
17	**Customer Revenues**	(1,427,312)	(1,507,442)	$ (80,130)	5.61%
18	**Subtotal Under/(Over) Recovery**	**$ (398,107)**	**$ (360,008)**	**$ 38,099**	
19	2020 PABA Ending Balance	$ 500,466		$ (500,466)	
20	2020 ERRA BA Ending Balance	$ (43,529)		$ 43,529	
21	2020 PUBA BSF Year-End Balance	$ (57,370)		$ 57,370	
22	2018 ERRA Review Decision	$ (1,460)		$ 1,460	
22	**Total Under/(Over) Recovery**	**$ 0**	**$ (360,008)**	**$ (360,008)**	
23	**2021 PABA**				
24	Beginning Balance		$ 435,255		
25	Activity		$ (360,008)		
26	**Ending Balance**		**$ 75,247**		

[1] This includes the energy component from PCC-1 REC sales and the line loss adjustment

1. Customer Revenues

Customer revenues are projected to be higher than forecast in 2021 by approximately 5.6 percent primarily due to higher than forecast customer sales in 2021.

ATTACHMENT C

Pacific Gas & Electric Company
2022 ERRA Forecast - November Update
Effective Saturday, January 1, 2022

BDLD RESULTS

Class/Schedule	Total Revenue At Present	Generation Revenue	TO Revenue	TAC Revenue	TRBAA Revenue	T-ECRA Revenue	RS Revenue	Dist Revenue	PPP Revenue	ND Revenue	DWR Bond Revenue	CTC Revenue	ECRA Revenue	NSGC Revenue	Climate Credit & EITE Revenue	CIA Revenue	PCIA Revenue	Total Proposed Revenue
RESIDENTIAL																		
E-1	$2,165,518,264	$1,185,105,074	$284,361,930	$5,792,670	-$24,695,065	$0	$1,310,614	$867,508,680	$125,917,897	$7,059,498	$41,626,079	$2,064,102	$2,417,807	$22,963,395	-$104,855,697	$925,087		$2,417,502,070
D-CARE	$726,650,075	$633,437,042	$151,991,149	$3,096,176	-$13,199,486	$0	$700,515	$60,095,403	$20,010,250	$3,773,332	$0	$1,103,263	$1,292,318	$12,273,936	-$51,523,657	-$19,025,142		$804,025,099
TOTAL RES	$2,892,168,338	$1,818,542,116	$436,353,079	$8,888,845	-$37,894,551	$0	$2,011,129	$927,604,083	$145,928,146	$10,832,829	$41,626,079	$3,167,365	$3,710,125	$35,237,331	-$156,379,354	($18,100,054)		$3,221,527,169
SMALL L&P																		
B-1	$517,239,530	$276,410,632	$51,954,722	$1,408,005	-$6,002,548	$0	$239,470	$215,797,330	$31,261,366	$1,715,925	$10,723,588	$478,773	$587,687	$3,640,848	-$13,637,051	$0		$574,578,749
B-6	$114,789,074	$66,519,906	$12,825,838	$347,550	-$1,481,662	$0	$59,151	$46,130,128	$7,190,671	$423,557	$2,651,675	$118,180	$145,064	$898,703	-$872,761	$0		$134,956,001
B-15	$11,981	$1,730	$326	$9	-$38	$0	$2	$10,090	$196	$11	$67	$3	$4	$23	-$1,572	$0		$10,850
TC-1	$3,202,269	$1,658,986	$336,650	$9,124	-$38,895	$0	$1,552	$1,488,055	$60,111	$11,119	$69,659	$3,102	$3,808	$23,592	$0	$0		$3,626,863
TOTAL SMALL	$635,242,853	$344,591,255	$65,117,536	$1,764,688	-$7,523,143	$0	$300,175	$263,425,603	$38,512,345	$2,150,611	$13,444,990	$600,058	$736,563	$4,563,166	-$14,511,383			$713,172,463
MEDIUM L&P																		
B-10 T	$140,163	$103,301	$22,229	$647	-$2,758	$0	$103	$23,179	$13,136	$788	$4,939	$237	$270	$1,596	$0	$0		$167,667
B-10 P	$4,443,190	$2,762,009	$717,021	$14,591	-$62,204	$0	$3,324	$1,267,520	$300,494	$17,782	$111,404	$5,341	$6,090	$35,994	-$13,809	$0		$5,165,556
B-10 S	$542,477,059	$353,311,375	$75,100,641	$1,679,237	-$7,158,852	$0	$348,139	$158,290,107	$34,877,643	$2,046,473	$12,777,606	$614,632	$700,897	$4,142,430	-$475,526	$0		$636,254,802
TOTAL MEDIUM	$547,060,412	$356,176,685	$75,839,891	$1,694,475	-$7,223,813	$0	$351,566	$159,580,806	$35,191,272	$2,065,043	$12,893,949	$620,210	$707,257	$4,180,020	-$489,335			$641,588,025
B-19 CLASS																		
B-19 FIRM T	$1,106,465	$830,999	$204,659	$4,398	-$18,750	$0	$950	$167,966	$86,286	$5,360	$33,580	$1,512	$1,836	$10,849	-$162,731	$0		$1,166,915
B-19 V T	$1,323,449	$1,139,482	$205,238	$6,338	-$27,022	$0	$960	$100,955	$124,355	$7,725	$48,395	$2,179	$2,646	$15,636	$0	$0		$1,626,887
Total B-19 T	$2,429,914	$1,970,481	$409,898	$10,737	-$45,771	$0	$1,910	$268,921	$210,641	$13,085	$81,975	$3,691	$4,481	$26,485	-$162,731			$2,793,802
B-19 FIRM P	$50,175,512	$34,210,332	$7,011,031	$186,052	-$793,168	$0	$32,601	$12,943,853	$3,649,880	$226,740	$1,420,534	$63,965	$77,656	$458,962	-$205,940	$0		$59,282,498
B-19 V P	$19,284,395	$13,551,109	$2,654,379	$75,838	-$323,310	$0	$12,305	$4,521,309	$1,482,712	$92,423	$576,513	$26,073	$31,654	$187,082	$0	$0		$22,888,087
Total B-19 P	$69,459,907	$47,761,441	$9,665,410	$261,890	-$1,116,478	$0	$44,905	$17,465,162	$5,132,592	$319,163	$1,997,047	$90,039	$109,310	$646,044	-$205,940			$82,170,585
B-19 FIRM S	$182,034,305	$128,885,639	$20,499,588	$637,584	-$2,718,123	$0	$95,145	$48,737,863	$12,946,207	$777,019	$4,868,059	$219,204	$266,121	$1,572,827	-$246,187	$0		$216,540,946
B-19 V S	$391,628,674	$277,838,733	$41,584,710	$1,402,152	-$5,977,596	$0	$192,800	$105,227,482	$28,404,137	$1,708,792	$10,672,323	$482,065	$585,244	$3,458,903	-$310,956	$0		$465,268,788
Total B-19 S	$573,662,979	$406,724,372	$62,084,297	$2,039,737	-$8,695,719	$0	$287,945	$153,965,345	$41,350,344	$2,485,811	$15,540,382	$701,269	$851,366	$5,031,730	-$557,143			$681,809,734
B-19 T	$2,429,914	$1,970,481	$409,898	$10,737	-$45,771	$0	$1,910	$268,921	$210,641	$13,085	$81,975	$3,691	$4,481	$26,485	-$162,731	$0		$2,793,802
B-19 P	$69,459,907	$47,761,441	$9,665,410	$261,890	-$1,116,478	$0	$44,905	$17,465,162	$5,132,592	$319,163	$1,997,047	$90,039	$109,310	$646,044	-$205,940	$0		$82,170,585
B-19 S	$573,662,979	$406,724,372	$62,084,297	$2,039,737	-$8,695,719	$0	$287,945	$153,965,345	$41,350,344	$2,485,811	$15,540,382	$701,269	$851,366	$5,031,730	-$557,143	$0		$681,809,734
TOTAL B-19	$645,552,800	$456,456,294	$72,159,605	$2,312,363	-$9,857,968	$0	$334,760	$171,699,428	$46,693,577	$2,818,058	$17,619,404	$794,999	$965,157	$5,704,259	-$925,815			$766,774,122
STREETLIGHTS	$22,612,774	$8,850,988	$1,711,625	$54,336	-$231,642	$0	$7,889	$13,452,650	$374,961	$66,218	$414,862	$15,404	$22,679	$118,591	$0	$0		$24,858,560
STANDBY																		
STANDBY T	$30,696,681	$28,344,211	$2,140,154	$194,609	-$829,649	$0	$62,476	$4,948,210	$3,950,254	$237,168	$1,485,871	$49,725	$81,228	$998,508	-$2,171,144	$0		$39,491,621
STANDBY P	$2,993,319	$981,093	$68,335	$5,359	-$22,845	$0	$1,996	$2,159,273	$128,714	$6,531	$40,915	$1,369	$2,237	$27,495	-$1,257,174	$0		$2,143,296
STANDBY S	$1,003,313	$549,873	$25,078	$3,426	-$14,605	$0	$731	$531,658	$79,564	$4,175	$26,157	$875	$1,430	$17,577	-$59,346	$0		$1,166,593
TOTAL STANDBY	$34,693,313	$29,875,178	$2,233,567	$203,393	-$867,099	$0	$65,202	$7,639,140	$4,158,531	$247,874	$1,552,942	$51,970	$84,894	$1,043,580	-$3,487,664			$42,801,510
AGRICULTURE																		
AG-A	$135,315,312	$52,047,951	$8,828,503	$289,330	-$1,233,460	$0	$40,693	$79,100,900	$6,647,272	$352,604	$2,209,081	$91,959	$120,763	$716,727	-$2,499,528			$146,712,795
AG-B	$245,251,882	$113,104,946	$16,600,303	$544,030	-$2,319,284	$0	$76,515	$128,922,972	$12,002,223	$663,004	$4,153,753	$172,911	$227,072	$1,347,667	-$525,957			$274,970,155
AG-C	$736,226,745	$465,394,003	$80,016,130	$2,622,310	-$11,179,321	$0	$368,814	$240,568,985	$51,016,264	$3,195,788	$20,021,756	$833,458	$1,094,526	$6,495,972	-$489,204			$859,959,482
TOTAL AG	$1,116,793,939	$630,546,899	$105,444,936	$3,455,669	-$14,732,064	$0	$486,022	$448,592,858	$69,665,758	$4,211,397	$26,384,590	$1,098,328	$1,442,362	$8,560,366	-$3,514,689			$1,281,642,432
B-20 CLASS																		
B-20 FIRM T	$216,845,967	$203,142,204	$36,148,103	$1,184,388	-$5,049,235	$0	$177,618	$2,748,247	$21,362,594	$1,443,405	$9,042,995	$353,699	$494,352	$2,434,922	-$4,110,571			$269,372,722
FPP T																		
TOTAL	$216,845,967	$203,142,204	$36,148,103	$1,184,388	-$5,049,235	$0	$177,618	$2,748,247	$21,362,594	$1,443,405	$9,042,995	$353,699	$494,352	$2,434,922	-$4,110,571			$269,372,722
B-20 FIRM P	$301,871,495	$234,334,799	$37,206,094	$1,311,758	-$5,592,231	$0	$173,589	$59,516,203	$25,214,980	$1,598,629	$10,015,483	$408,048	$547,515	$2,696,774	-$1,424,573			$366,007,067
FPP P																		
TOTAL	$301,871,495	$234,334,799	$37,206,094	$1,311,758	-$5,592,231	$0	$173,589	$59,516,203	$25,214,980	$1,598,629	$10,015,483	$408,048	$547,515	$2,696,774	-$1,424,573			$366,007,067
B-20 FIRM S	$94,904,065	$71,069,754	$11,172,230	$388,532	-$1,656,374	$0	$51,889	$21,654,882	$7,756,355	$473,501	$2,966,505	$123,754	$162,169	$798,763	-$157,227			$114,804,734
FPP S																		
TOTAL	$94,904,065	$71,069,754	$11,172,230	$388,532	-$1,656,374	$0	$51,889	$21,654,882	$7,756,355	$473,501	$2,966,505	$123,754	$162,169	$798,763	-$157,227			$114,804,734
B-20 T	$216,845,967	$203,142,204	$36,148,103	$1,184,388	-$5,049,235	$0	$177,618	$2,748,247	$21,362,594	$1,443,405	$9,042,995	$353,699	$494,352	$2,434,922	-$4,110,571			$269,372,722
B-20 P	$301,871,495	$234,334,799	$37,206,094	$1,311,758	-$5,592,231	$0	$173,589	$59,516,203	$25,214,980	$1,598,629	$10,015,483	$408,048	$547,515	$2,696,774	-$1,424,573			$366,007,067
B-20 S	$94,904,065	$71,069,754	$11,172,230	$388,532	-$1,656,374	$0	$51,889	$21,654,882	$7,756,355	$473,501	$2,966,505	$123,754	$162,169	$798,763	-$157,227			$114,804,734
TOTAL B-20	$613,621,527	$508,546,757	$84,526,427	$2,884,678	-$12,297,840	$0	$403,096	$83,919,332	$54,333,929	$3,515,535	$22,024,983	$885,501	$1,204,036	$5,930,459	-$5,692,370			$750,184,523
SYSTEM	**$6,507,745,956**	**$4,153,586,172**	**$843,386,666**	**$21,258,448**	**-$90,628,120**	**$0**	**$3,959,839**	**$2,075,913,899**	**$394,858,519**	**$25,907,566**	**$135,961,800**	**$7,233,835**	**$8,873,074**	**$65,337,770**	**-$185,000,610**	**-$18,100,054**	**$0**	**$7,442,548,804**

Pacific Gas & Electric Company
2022 ERRA Forecast - November Update
Effective Saturday, January 1, 2022

BDLD RESULTS

Class/Schedule	Total Sales (kWh)	Revenue At Present Rates	Generation Rates	TO Rates	TAC Rates	TRBAA Rates	T-ECRA Rates	RS Rates	Dist Rates	PPP Rates	ND Rates	DWR Bond Rates	CTC Rates	ECRA Rates	NSGC Rates	Climate Credit & EITE Rates	CIA Rates	PCIA Rates	Total Proposed Rates	Percent Change
RESIDENTIAL																				
E-1	7,621,948,072	$0.28412	$0.15549	$0.03731	$0.00076	-$0.00324	$0.00000	$0.00017	$0.11382	$0.01652	$0 00093	$0 00546	$0.00027	$0 00032	$0.00301	-$0.01376	$0.00012		$0.31718	11.6%
D-CARE	4,073,931,793	$0.17837	$0.15549	$0.03731	$0.00076	-$0.00324	$0.00000	$0.00017	$0.01475	$0.00491	$0.00093	$0.00000	$0.00027	$0.00032	$0.00301	-$0.01265	-$0.00467		$0.19736	10.6%
TOTAL RES	11,695,879,865	$0.24728	$0.15549	$0.03731	$0.00076	-$0.00324	$0.00000	$0.00017	$0.07931	$0.01248	$0 00093	$0 00356	$0.00027	$0 00032	$0.00301	-$0.01337	-$0.00155		$0.27544	11.4%
SMALL L&P																				
B-1	1,852,638,350	$0.27919	$0.14920	$0.02804	$0.00076	-$0.00324	$0.00000	$0.00013	$0.11648	$0.01687	$0 00093	$0 00579	$0.00026	$0 00032	$0.00197	-$0.00736			$0.31014	11.1%
B-6	457,303,143	$0.25101	$0.14546	$0.02805	$0.00076	-$0.00324	$0.00000	$0.00013	$0.10087	$0.01572	$0 00093	$0 00580	$0.00026	$0 00032	$0.00197	-$0.00191			$0.29511	17.6%
B-15	11,608	$1.03211	$0.14903	$0.02804	$0.00076	-$0.00324	$0.00000	$0.00013	$0.86920	$0.01690	$0 00093	$0 00580	$0.00026	$0 00032	$0.00197	-$0.13539			$0.93471	-9.4%
TC-1	12,004,618	$0.26675	$0.13820	$0.02804	$0.00076	-$0.00324	$0.00000	$0.00013	$0.12396	$0.00501	$0.00093	$0.00580	$0.00026	$0.00032	$0.00197	$0.00000			$0.30212	13.3%
TOTAL SMALL	2,321,957,719	$0.27358	$0.14841	$0.02804	$0.00076	-$0.00324	$0.00000	$0.00013	$0.11345	$0.01659	$0 00093	$0 00579	$0.00026	$0 00032	$0.00197	-$0.00625			$0.30714	12.3%
MEDIUM L&P																				
B-10 T	851,163	$0.16467	$0.12136	$0.02612	$0.00076	-$0.00324	$0.00000	$0.00012	$0.02723	$0.01543	$0 00093	$0 00580	$0.00028	$0 00032	$0.00187	$0.00000			$0.19699	19.6%
B-10 P	19,198,641	$0.23143	$0.14386	$0.03735	$0.00076	-$0.00324	$0.00000	$0.00017	$0.06602	$0.01565	$0 00093	$0 00580	$0.00028	$0 00032	$0.00187	-$0.00072			$0.26906	16.3%
B-10 S	2,209,522,176	$0.24552	$0.15990	$0.03399	$0.00076	-$0.00324	$0.00000	$0.00016	$0.07164	$0.01579	$0.00093	$0.00578	$0.00028	$0.00032	$0.00187	-$0.00022			$0.28796	17.3%
TOTAL MEDIUM	2,229,571,981	$0.24537	$0.15975	$0.03402	$0.00076	-$0.00324	$0.00000	$0.00016	$0.07157	$0.01578	$0 00093	$0 00578	$0.00028	$0 00032	$0.00187	-$0.00022			$0.28776	17.3%
B-19 CLASS																				
B-19 FIRM T	5,786,937	$0.19120	$0.14360	$0.03537	$0.00076	-$0.00324	$0.00000	$0.00016	$0.02903	$0.01491	$0 00093	$0 00580	$0.00026	$0 00032	$0.00187	-$0.02812			$0.20165	5.5%
B-19 V T	8,340,056	$0.15869	$0.13663	$0.02461	$0.00076	-$0.00324	$0.00000	$0.00012	$0.01210	$0.01491	$0.00093	$0.00580	$0.00026	$0.00032	$0.00187	$0.00000			$0.19507	22.9%
Total B-19 T	14,126,994	$0.17201	$0.13948	$0.02902	$0.00076	-$0.00324	$0.00000	$0.00014	$0.01904	$0.01491	$0 00093	$0 00580	$0.00026	$0 00032	$0.00187	-$0.01152			$0.19776	15.0%
B-19 FIRM P	244,804,800	$0.20496	$0.13975	$0.02864	$0.00076	-$0.00324	$0.00000	$0.00013	$0.05287	$0.01491	$0 00093	$0 00580	$0.00026	$0 00032	$0.00187	-$0.00084			$0.24216	18.2%
B-19 V P	99,787,163	$0.19326	$0.13580	$0.02660	$0.00076	-$0.00324	$0.00000	$0.00012	$0.04531	$0.01486	$0.00093	$0.00578	$0.00026	$0.00032	$0.00187	$0.00000			$0.22937	18.7%
Total B-19 P	344,591,963	$0.20157	$0.13860	$0.02805	$0.00076	-$0.00324	$0.00000	$0.00013	$0.05068	$0.01489	$0 00093	$0 00580	$0.00026	$0 00032	$0.00187	-$0.00060			$0.23846	18.3%
B-19 FIRM S	838,926,763	$0.21698	$0.15363	$0.02444	$0.00076	-$0.00324	$0.00000	$0.00011	$0.05810	$0.01543	$0 00093	$0 00580	$0.00026	$0 00032	$0.00187	-$0.00029			$0.25812	19.0%
B-19 V S	1,844,937,150	$0.21227	$0.15060	$0.02254	$0.00076	-$0.00324	$0.00000	$0.00010	$0.05704	$0.01540	$0.00093	$0.00578	$0.00026	$0.00032	$0.00187	-$0.00017			$0.25219	18.8%
Total B-19 S	2,683,863,913	$0.21375	$0.15154	$0.02313	$0.00076	-$0.00324	$0.00000	$0.00011	$0.05737	$0.01541	$0 00093	$0 00579	$0.00026	$0 00032	$0.00187	-$0.00021			$0.25404	18.9%
B-19 T	14,126,994	$0.17201	$0.13948	$0.02902	$0.00076	-$0.00324	$0.00000	$0.00014	$0.01904	$0.01491	$0 00093	$0 00580	$0.00026	$0 00032	$0.00187	-$0.01152			$0.19776	15.0%
B-19 P	344,591,963	$0.20157	$0.13860	$0.02805	$0.00076	-$0.00324	$0.00000	$0.00013	$0.05068	$0.01489	$0 00093	$0 00580	$0.00026	$0 00032	$0.00187	-$0.00060			$0.23846	18.3%
B-19 S	2,683,863,913	$0.21375	$0.15154	$0.02313	$0.00076	-$0.00324	$0.00000	$0.00011	$0.05737	$0.01541	$0.00093	$0.00579	$0.00026	$0.00032	$0.00187	-$0.00021			$0.25404	18.9%
TOTAL B-19	3,042,582,870	$0.21217	$0.15002	$0.02372	$0.00076	-$0.00324	$0.00000	$0.00011	$0.05643	$0.01535	$0 00093	$0 00579	$0.00026	$0 00032	$0.00187	-$0.00030			$0.25201	18.8%
STREETLIGHTS	71,494,354	$0.31629	$0.12380	$0.02394	$0.00076	-$0.00324	$0.00000	$0.00011	$0.18816	$0.00524	$0 00093	$0 00580	$0.00022	$0 00032	$0.00166	$0.00000			$0.34770	9.9%
STANDBY																				
STANDBY T	256,064,404	$0.11988	$0.11069	$0.00836	$0.00076	-$0.00324	$0.00000	$0.00024	$0.01932	$0.01543	$0 00093	$0 00580	$0.00019	$0 00032	$0.00390	-$0.00848			$0.15423	28.7%
STANDBY P	7,050,967	$0.42453	$0.13914	$0.00969	$0.00076	-$0.00324	$0.00000	$0.00028	$0.30624	$0.01825	$0 00093	$0 00580	$0.00019	$0 00032	$0.00390	-$0.17830			$0.30397	-28.4%
STANDBY S	4,507,630	$0.22258	$0.12199	$0.00556	$0.00076	-$0.00324	$0.00000	$0.00016	$0.11795	$0.01765	$0.00093	$0.00580	$0.00019	$0.00032	$0.00390	-$0.01317			$0.25880	16.3%
TOTAL STANDBY	267,623,002	$0.12964	$0.11163	$0.00835	$0.00076	-$0.00324	$0.00000	$0.00024	$0.02854	$0.01554	$0 00093	$0 00580	$0.00019	$0 00032	$0.00390	-$0.01303			$0.15993	23.4%
AGRICULTURE																				
AG-A	380,697,410	$0.35544	$0.13672	$0.02319	$0.00076	-$0.00324	$0.00000	$0.00011	$0.20778	$0.01746	$0 00093	$0 00580	$0.00024	$0 00032	$0.00188	-$0.00657			$0.38538	8.4%
AG-B	715,828,308	$0.34261	$0.15801	$0.02319	$0.00076	-$0.00324	$0.00000	$0.00011	$0.18010	$0.01677	$0 00093	$0 00580	$0.00024	$0 00032	$0.00188	-$0.00073			$0.38413	12.1%
AG-C	3,450,407,620	$0.21337	$0.13488	$0.02319	$0.00076	-$0.00324	$0.00000	$0.00011	$0.06972	$0.01479	$0.00093	$0.00580	$0.00024	$0.00032	$0.00188	-$0.00014			$0.24923	16.8%
TOTAL AG	4,546,933,338	$0.24561	$0.13868	$0.02319	$0.00076	-$0.00324	$0.00000	$0.00011	$0.09866	$0.01532	$0 00093	$0 00580	$0.00024	$0 00032	$0.00188	-$0.00077			$0.28187	14.8%
B-20 CLASS																				
B-20 FIRM T	1,558,405,758	$0.13915	$0.13035	$0.02320	$0.00076	-$0.00324	$0.00000	$0.00011	$0.00176	$0.01371	$0 00093	$0 00580	$0.00023	$0 00032	$0.00156	-$0.00264			$0.17285	24.2%
FPP T																				
TOTAL	1,558,405,758	$0.13915	$0.13035	$0.02320	$0.00076	-$0.00324	$0.00000	$0.00011	$0.00176	$0.01371	$0 00093	$0 00580	$0.00023	$0 00032	$0.00156	-$0.00264			$0.17285	24.2%
B-20 FIRM P	1,725,997,311	$0.17490	$0.13577	$0.02156	$0.00076	-$0.00324	$0.00000	$0.00010	$0.03448	$0.01461	$0 00093	$0 00580	$0.00024	$0 00032	$0.00156	-$0.00083			$0.21206	21.2%
FPP P																				
TOTAL	1,725,997,311	$0.17490	$0.13577	$0.02156	$0.00076	-$0.00324	$0.00000	$0.00010	$0.03448	$0.01461	$0 00093	$0 00580	$0.00024	$0 00032	$0.00156	-$0.00083			$0.21206	21.2%
B-20 FIRM S	511,226,505	$0.18564	$0.13902	$0.02185	$0.00076	-$0.00324	$0.00000	$0.00010	$0.04236	$0.01517	$0 00093	$0 00580	$0.00024	$0 00032	$0.00156	-$0.00031			$0.22457	21.0%
FPP S																				
TOTAL	511,226,505	$0.18564	$0.13902	$0.02185	$0.00076	-$0.00324	$0.00000	$0.00010	$0.04236	$0.01517	$0 00093	$0 00580	$0.00024	$0 00032	$0.00156	-$0.00031			$0.22457	21.0%
B-20 T	1,558,405,758	$0.13915	$0.13035	$0.02320	$0.00076	-$0.00324	$0.00000	$0.00011	$0.00176	$0.01371	$0 00093	$0 00580	$0.00023	$0 00032	$0.00156	-$0.00264			$0.17285	24.2%
B-20 P	1,725,997,311	$0.17490	$0.13577	$0.02156	$0.00076	-$0.00324	$0.00000	$0.00010	$0.03448	$0.01461	$0 00093	$0 00580	$0.00024	$0 00032	$0.00156	-$0.00083			$0.21206	21.2%
B-20 S	511,226,505	$0.18564	$0.13902	$0.02185	$0.00076	-$0.00324	$0.00000	$0.00010	$0.04236	$0.01517	$0.00093	$0.00580	$0.00024	$0.00032	$0.00156	-$0.00031			$0.22457	21.0%
TOTAL B-20	3,795,629,574	$0.16167	$0.13398	$0.02227	$0.00076	-$0.00324	$0.00000	$0.00011	$0.02211	$0.01431	$0 00093	$0 00580	$0.00023	$0 00032	$0.00156	-$0.00150			$0.19764	22.3%
SYSTEM	**27,971,672,702**	**$0.23265**	**$0.14849**	**$0.03015**	**$0.00076**	**-$0.00324**	**$0.00000**	**$0.00014**	**$0.07421**	**$0.01412**	**$0.00093**	**$0.00486**	**$0.00026**	**$0.00032**	**$0.00234**	**-$0.00661**	**-$0.00065**	**$0.00000**	**$0.26607**	**14.4%**

Pacific Gas & Electric Company
2022 ERRA Forecast - November Update
Effective Saturday, January 1, 2022

DA/CCA RESULTS

Class/Schedule	Total Revenue At Present	TO Revenue	TAC Revenue	TRBAA Revenue	T-ECRA Revenue	RS Revenue	Dist Revenue	PPP Revenue	ND Revenue	DWR Bond Revenue	CTC Revenue	ECRA Revenue	NSGC Revenue	Climate Credit & EITE Revenue	CIA Revenue	PCIA Revenue	Total Proposed Revenue
RESIDENTIAL																	
E-1	$2,940,720,328	$506,464,172	$10,317,062	-$43,983,263	$0	$2,334,279	$1,562,604,316	$224,266,671	$12,573,352	$76,541,316	$3,676,286	$4,306,255	$40,899,142	-$206,500,283	$31,884,729	$163,125,780	$2,388,509,813
D-CARE	$272,896,377	$99,735,542	$2,031,689	-$8,661,411	$0	$459,686	$39,031,469	$13,130,588	$2,476,034	$0	$723,973	$848,033	$8,054,291	-$43,556,375	-$13,784,674	$29,455,794	$129,944,637
TOTAL RES	$3,213,616,705	$606,199,713	$12,348,751	-$52,644,675	$0	$2,793,965	$1,601,635,785	$237,397,258	$15,049,386	$76,541,316	$4,400,259	$5,154,288	$48,953,433	-$250,056,658	$18,100,054	$192,581,574	$2,518,454,450
SMALL L&P																	
B-1	$908,318,843	$124,232,463	$3,366,806	-$14,353,225	$0	$572,587	$484,867,243	$74,767,819	$4,103,100	$25,647,948	$1,144,837	$1,405,271	$8,705,955	-$16,862,188	$0	$50,568,416	$748,167,032
B-6	$141,469,082	$20,510,161	$555,777	-$2,369,364	$0	$94,592	$74,549,366	$11,439,181	$677,321	$4,204,571	$188,984	$231,976	$1,437,139	-$1,120,538	$0	$8,242,511	$118,641,674
B-15	$241,623	$10,452	$283	-$1,208	$0	$48	$203,716	$6,300	$345	$2,152	$96	$118	$732	-$30,168	$0	$4,898	$197,767
TC-1	$5,451,841	$750,299	$20,334	-$86,686	$0	$3,458	$3,164,138	$133,972	$24,781	$155,252	$6,914	$8,487	$52,579	$0	$0	$296,387	$4,529,915
TOTAL SMALL	$1,055,481,389	$145,503,374	$3,943,200	-$16,810,483	$0	$670,685	$562,784,463	$86,347,272	$4,805,546	$30,009,922	$1,340,832	$1,645,852	$10,196,405	-$18,012,894		$59,112,212	$871,536,388
MEDIUM L&P																	
B-10 T	$137,265	$31,881	$785	-$3,347	$0	$148	$33,198	$15,944	$957	$5,995	$287	$328	$1,937	$0	$0	$12,763	$100,876
B-10 P	$5,511,306	$1,112,418	$25,620	-$109,220	$0	$5,157	$2,083,064	$524,172	$31,222	$193,885	$9,377	$10,693	$63,200	$0	$0	$408,385	$4,357,974
B-10 S	$876,248,187	$159,995,035	$4,008,366	-$17,088,297	$0	$741,766	$362,325,203	$83,229,523	$4,884,964	$30,488,366	$1,467,138	$1,673,052	$9,888,049	-$609,566	$0	$61,650,577	$702,654,175
TOTAL MEDIUM	$881,896,758	$161,139,334	$4,034,771	-$17,200,865	$0	$747,070	$364,441,465	$83,769,640	$4,917,143	$30,688,246	$1,476,802	$1,684,073	$9,953,185	-$609,566		$62,071,725	$707,113,024
B-19 CLASS																	
B-19 FIRM T	$623,502	$150,677	$3,975	-$16,945	$0	$698	$131,248	$77,980	$4,844	$30,348	$1,367	$1,659	$9,805	$0	$0	$60,559	$456,214
B-19 V T	$794,733	$157,150	$6,562	-$27,974	$0	$728	$84,266	$128,738	$7,997	$50,101	$2,256	$2,739	$16,187	$0	$0	$98,208	$526,957
Total B-19 T	$1,418,234	$307,826	$10,537	-$44,919	$0	$1,427	$215,514	$206,718	$12,841	$80,448	$3,623	$4,398	$25,992	$0		$158,767	$983,172
B-19 FIRM P	$62,706,479	$12,196,092	$375,000	-$1,598,683	$0	$56,560	$23,080,377	$7,356,580	$457,009	$2,863,182	$128,926	$156,521	$925,069	-$57,790	$0	$4,650,871	$50,589,714
B-19 V P	$24,902,406	$4,964,924	$141,898	-$604,932	$0	$23,073	$8,633,651	$2,783,684	$172,929	$1,083,411	$48,785	$59,227	$350,040	$0	$0	$1,981,098	$19,637,788
Total B-19 P	$87,608,885	$17,161,017	$516,897	-$2,203,614	$0	$79,632	$31,714,028	$10,140,264	$629,939	$3,946,593	$177,711	$215,748	$1,275,109	-$57,790		$6,631,969	$70,227,502
B-19 FIRM S	$374,087,082	$62,776,955	$2,139,200	-$9,119,749	$0	$291,205	$151,289,631	$43,359,804	$2,607,027	$16,294,724	$735,465	$892,881	$5,277,093	-$404,053	$0	$26,915,754	$303,055,936
B-19 V S	$839,994,323	$135,341,505	$5,041,140	-$21,491,176	$0	$627,584	$341,362,547	$101,976,150	$6,143,598	$38,208,481	$1,733,163	$2,104,122	$12,435,750	-$515,980	$0	$59,677,095	$682,643,979
Total B-19 S	$1,214,081,405	$198,118,460	$7,180,341	-$30,610,925	$0	$918,789	$492,652,178	$145,335,954	$8,750,624	$54,503,205	$2,468,629	$2,997,003	$17,712,843	-$920,033		$86,592,849	$985,699,915
B-19 T	$1,418,234	$307,826	$10,537	-$44,919	$0	$1,427	$215,514	$206,718	$12,841	$80,448	$3,623	$4,398	$25,992	$0	$0	$158,767	$983,172
B-19 P	$87,608,885	$17,161,017	$516,897	-$2,203,614	$0	$79,632	$31,714,028	$10,140,264	$629,939	$3,946,593	$177,711	$215,748	$1,275,109	-$57,790	$0	$6,631,969	$70,227,502
B-19 S	$1,214,081,405	$198,118,460	$7,180,341	-$30,610,925	$0	$918,789	$492,652,178	$145,335,954	$8,750,624	$54,503,205	$2,468,629	$2,997,003	$17,712,843	-$920,033	$0	$86,592,849	$985,699,915
TOTAL B-19	$1,303,108,525	$215,587,303	$7,707,774	-$32,859,459	$0	$999,848	$524,581,720	$155,682,936	$9,393,404	$58,530,247	$2,649,963	$3,217,148	$19,013,944	-$977,824		$93,383,585	$1,056,910,589
STREETLIGHTS	$31,172,529	$3,775,790	$119,863	-$510,994	$0	$17,402	$19,671,230	$790,076	$146,076	$915,172	$33,980	$50,030	$261,607	$0	$0	$1,432,837	$26,703,068
STANDBY																	
STANDBY T	$3,886,494	$303,152	$27,064	-$115,376	$0	$8,850	$1,569,300	$549,348	$32,982	$206,635	$6,915	$11,296	$138,859	$0	$0	$299,453	$3,038,479
STANDBY P	$2,396,316	$65,072	$5,476	-$23,345	$0	$1,900	$2,097,317	$131,529	$6,673	$41,810	$1,399	$2,286	$28,096	-$251,732	$0	$21,771	$2,128,252
STANDBY S	$418,987	$9,788	$1,390	-$5,925	$0	$285	$301,087	$32,279	$1,694	$10,612	$355	$580	$7,131	-$803	$0	$15,707	$374,179
TOTAL STANDBY	$6,701,796	$378,012	$33,929	-$144,646	$0	$11,036	$3,967,704	$713,156	$41,349	$259,056	$8,669	$14,162	$174,086	-$252,534		$336,931	$5,540,911
AGRICULTURE																	
AG-A	$31,511,779	$2,520,463	$82,601	-$352,142	$0	$11,617	$22,159,577	$1,897,740	$100,666	$630,646	$26,253	$34,477	$204,619	-$596,277	$0	$1,098,850	$27,819,090
AG-B	$61,909,477	$5,656,900	$185,389	-$790,344	$0	$26,074	$41,167,718	$4,090,008	$225,933	$1,415,478	$58,923	$77,380	$459,246	-$123,954	$0	$2,421,186	$54,869,936
AG-C	$149,291,739	$25,361,958	$831,169	-$3,543,404	$0	$116,899	$59,152,704	$16,170,144	$1,012,939	$6,346,107	$264,173	$346,922	$2,058,967	-$470,384	$0	$10,689,932	$118,338,127
TOTAL AG	$242,712,996	$33,539,321	$1,099,160	-$4,685,891	$0	$154,591	$122,479,999	$22,157,892	$1,339,537	$8,392,231	$349,350	$458,778	$2,722,832	-$1,190,615		$14,209,968	$201,027,153
B-20 CLASS																	
B-20 FIRM T	$212,021,649	$69,775,061	$2,855,931	-$12,175,283	$0	$324,353	-$3,495,141	$51,511,892	$3,480,500	$18,701,797	$852,878	$1,192,037	$5,871,357	-$9,265,986	$0	$23,008,367	$152,637,763
FPP T	$4,445,890	$0	$0	$0	$0	$0	$665,331	$3,796,199	$280,256	$0	$0	$0	$0		$0	$0	$4,741,786
TOTAL	$216,467,539	$69,775,061	$2,855,931	-$12,175,283	$0	$324,353	-$2,829,810	$55,308,090	$3,760,756	$18,701,797	$852,878	$1,192,037	$5,871,357	-$9,265,986		$23,008,367	$157,379,549
B-20 FIRM P	$434,988,519	$93,713,443	$3,371,584	-$14,373,596	$0	$436,774	$155,434,850	$64,809,537	$4,108,923	$25,742,586	$1,048,798	$1,407,266	$6,931,462	-$3,125,115	$0	$28,860,358	$368,366,873
FPP P	$690,696	$0	$0	$0	$0	$0	$437,269	$254,529	$17,532	$0	$0	$0	$0		$0	$0	$709,330
TOTAL	$435,679,216	$93,713,443	$3,371,584	-$14,373,596	$0	$436,774	$155,872,119	$65,064,066	$4,126,455	$25,742,586	$1,048,798	$1,407,266	$6,931,462	-$3,125,115		$28,860,358	$369,076,203
B-20 FIRM S	$183,262,875	$34,651,856	$1,284,917	-$5,477,804	$0	$160,898	$69,678,726	$25,651,091	$1,565,918	$9,810,548	$409,268	$536,312	$2,641,593	-$334,657	$0	$12,716,197	$153,294,864
FPP S	$3,937,572	$0	$0	$0	$0	$0	$2,563,331	$1,379,788	$91,219	$0	$0	$0	$0		$0	$0	$4,034,338
TOTAL	$187,200,446	$34,651,856	$1,284,917	-$5,477,804	$0	$160,898	$72,242,058	$27,030,880	$1,657,137	$9,810,548	$409,268	$536,312	$2,641,593	-$334,657		$12,716,197	$157,329,203
B-20 T	$216,467,539	$69,775,061	$2,855,931	-$12,175,283	$0	$324,353	-$2,829,810	$55,308,090	$3,760,756	$18,701,797	$852,878	$1,192,037	$5,871,357	-$9,265,986	$0	$23,008,367	$157,379,549
B-20 P	$435,679,216	$93,713,443	$3,371,584	-$14,373,596	$0	$436,774	$155,872,119	$65,064,066	$4,126,455	$25,742,586	$1,048,798	$1,407,266	$6,931,462	-$3,125,115	$0	$28,860,358	$369,076,203
B-20 S	$187,200,446	$34,651,856	$1,284,917	-$5,477,804	$0	$160,898	$72,242,058	$27,030,880	$1,657,137	$9,810,548	$409,268	$536,312	$2,641,593	-$334,657	$0	$12,716,197	$157,329,203
TOTAL B-20	$839,347,201	$198,140,360	$7,512,432	-$32,026,683	$0	$922,026	$225,284,367	$147,403,036	$9,544,348	$54,254,932	$2,310,944	$3,135,614	$15,444,413	-$12,725,757		$64,584,922	$683,784,954
SYSTEM	**$7,574,037,898**	**$1,364,263,208**	**$36,799,879**	**-$156,883,696**	**$0**	**$6,316,624**	**$3,424,846,733**	**$734,261,266**	**$45,236,790**	**$259,591,122**	**$12,570,800**	**$15,359,946**	**$106,719,907**	**-$283,825,848**	**$18,100,054**	**$487,713,754**	**$6,071,070,538**

Pacific Gas & Electric Company
2022 ERRA Forecast - November Update
Effective Saturday, January 1, 2022

DA/CCA RESULTS

Class/Schedule	Total Sales (kWh)	Revenue At Present Rates	TO Rates	TAC Rates	TRBAA Rates	T-ECRA Rates	RS Rates	Dist Rates	PPP Rates	ND Rates	DWR Bond Rates	CTC Rates	ECRA Rates	NSGC Rates	Climate Credit & EITE Rates	CIA Rates	PCIA Rates	Total Proposed Rates	Percent Change
RESIDENTIAL																			
E-1	13,575,132,901	$0.21663	$0 03731	$0 00076	-$0.00324	$0.00000	$0.00017	$0.11511	$0.01652	$0.00093	$0.00564	$0.00027	$0.00032	$0.00301	-$0.01521	$0.00235	$0.01202	$0.17595	-18.8%
D-CARE	2,673,358,721	$0.10208	$0.03731	$0.00076	-$0.00324	$0.00000	$0.00017	$0 01460	$0.00491	$0.00093	$0.00000	$0.00027	$0.00032	$0.00301	-$0.01629	-$0.00516	$0.01102	$0.04861	-52.4%
TOTAL RES	16,248,491,622	$0.19778	$0 03731	$0 00076	-$0.00324	$0.00000	$0.00017	$0 09857	$0.01461	$0.00093	$0.00471	$0.00027	$0.00032	$0.00301	-$0.01539	$0.00111	$0.01185	$0.15500	-21.6%
SMALL L&P																			
B-1	4,430,007,855	$0.20504	$0 02804	$0 00076	-$0.00324	$0.00000	$0.00013	$0.10945	$0.01688	$0.00093	$0.00579	$0.00026	$0.00032	$0.00197	-$0.00381		$0.01141	$0.16889	-17.6%
B-6	731,285,082	$0.19345	$0 02805	$0 00076	-$0.00324	$0.00000	$0.00013	$0.10194	$0.01564	$0.00093	$0.00575	$0.00026	$0.00032	$0.00197	-$0.00153		$0.01127	$0.16224	-16.1%
B-15	372,702	$0.64830	$0 02804	$0 00076	-$0.00324	$0.00000	$0.00013	$0.54659	$0.01690	$0.00093	$0.00577	$0.00026	$0.00032	$0.00197	-$0.08094		$0.01314	$0.53063	-18.2%
TC-1	26,754,968	$0.20377	$0.02804	$0.00076	-$0.00324	$0.00000	$0.00013	$0.11826	$0.00501	$0.00093	$0.00580	$0.00026	$0.00032	$0.00197	$0.00000		$0.01108	$0.16931	-16.9%
TOTAL SMALL	5,188,420,608	$0.20343	$0 02804	$0 00076	-$0.00324	$0.00000	$0.00013	$0.10847	$0.01664	$0.00093	$0.00578	$0.00026	$0.00032	$0.00197	-$0.00347		$0.01139	$0.16798	-17.4%
MEDIUM L&P																			
B-10 T	1,033,148	$0.13286	$0 03086	$0 00076	-$0.00324	$0.00000	$0.00014	$0.03213	$0.01543	$0.00093	$0.00580	$0.00028	$0.00032	$0.00187	$0.00000		$0.01235	$0.09764	-26.5%
B-10 P	33,709,986	$0.16349	$0 03300	$0 00076	-$0.00324	$0.00000	$0.00015	$0.06179	$0.01555	$0.00093	$0.00575	$0.00028	$0.00032	$0.00187	$0.00000		$0.01211	$0.12928	-20.9%
B-10 S	5 274,165,892	$0.16614	$0.03034	$0.00076	-$0.00324	$0.00000	$0.00014	$0 06870	$0.01578	$0.00093	$0.00578	$0.00028	$0.00032	$0.00187	-$0.00012		$0.01169	$0.13323	-19.8%
TOTAL MEDIUM	5,308,909,027	$0.16612	$0 03035	$0 00076	-$0.00324	$0.00000	$0.00014	$0 06865	$0.01578	$0.00093	$0.00578	$0.00028	$0.00032	$0.00187	-$0.00011		$0.01169	$0.13319	-19.8%
B-19 CLASS																			
B-19 FIRM T	5,229,878	$0.11922	$0 02881	$0 00076	-$0.00324	$0.00000	$0.00013	$0.02510	$0.01491	$0.00093	$0.00580	$0.00026	$0.00032	$0.00187	$0.00000		$0.01158	$0.08723	-26.8%
B-19 V T	8,634,045	$0.09205	$0.01820	$0.00076	-$0.00324	$0.00000	$0.00008	$0 00976	$0.01491	$0.00093	$0.00580	$0.00026	$0.00032	$0.00187	$0.00000		$0.01137	$0.06103	-33.7%
Total B-19 T	13,863,923	$0.10230	$0 02220	$0 00076	-$0.00324	$0.00000	$0.00010	$0.01554	$0.01491	$0.00093	$0.00580	$0.00026	$0.00032	$0.00187	$0.00000		$0.01145	$0.07092	-30.7%
B-19 FIRM P	493,420,583	$0.12709	$0 02472	$0 00076	-$0.00324	$0.00000	$0.00011	$0.04678	$0.01491	$0.00093	$0.00580	$0.00026	$0.00032	$0.00187	-$0.00012		$0.00943	$0.10253	-19.3%
B-19 V P	186,707,305	$0.13338	$0.02659	$0.00076	-$0.00324	$0.00000	$0.00012	$0 04624	$0.01491	$0.00093	$0.00580	$0.00026	$0.00032	$0.00187	$0.00000		$0.01061	$0.10518	-21.1%
Total B-19 P	680,127,888	$0.12881	$0 02523	$0 00076	-$0.00324	$0.00000	$0.00012	$0.04663	$0.01491	$0.00093	$0.00580	$0.00026	$0.00032	$0.00187	-$0.00008		$0.00975	$0.10326	-19.8%
B-19 FIRM S	2,814,737,478	$0.13290	$0 02230	$0 00076	-$0.00324	$0.00000	$0.00010	$0 05375	$0.01540	$0.00093	$0.00579	$0.00026	$0.00032	$0.00187	-$0.00014		$0.00956	$0.10767	-19.0%
B-19 V S	6,633,079,029	$0.12664	$0.02040	$0.00076	-$0.00324	$0.00000	$0.00009	$0.05146	$0.01537	$0.00093	$0.00576	$0.00026	$0.00032	$0.00187	-$0.00008		$0.00900	$0.10292	-18.7%
Total B-19 S	9,447,816,507	$0.12850	$0 02097	$0 00076	-$0.00324	$0.00000	$0.00010	$0 05214	$0.01538	$0.00093	$0.00577	$0.00026	$0.00032	$0.00187	-$0.00010		$0.00917	$0.10433	-18.8%
B-19 T	13,863,923	$0.10230	$0 02220	$0 00076	-$0.00324	$0.00000	$0.00010	$0.01554	$0.01491	$0.00093	$0.00580	$0.00026	$0.00032	$0.00187	$0.00000		$0.01145	$0.07092	-30.7%
B-19 P	680,127,888	$0.12881	$0 02523	$0 00076	-$0.00324	$0.00000	$0.00012	$0.04663	$0.01491	$0.00093	$0.00580	$0.00026	$0.00032	$0.00187	-$0.00008		$0.00975	$0.10326	-19.8%
B-19 S	9,447,816,507	$0.12850	$0.02097	$0.00076	-$0.00324	$0.00000	$0.00010	$0 05214	$0.01538	$0.00093	$0.00577	$0.00026	$0.00032	$0.00187	-$0.00010		$0.00917	$0.10433	-18.8%
TOTAL B-19	10,141,808,317	$0.12849	$0 02126	$0 00076	-$0.00324	$0.00000	$0.00010	$0 05172	$0.01535	$0.00093	$0.00577	$0.00026	$0.00032	$0.00187	-$0.00010		$0.00921	$0.10421	-18.9%
STREETLIGHTS	157,714,232	$0.19765	$0 02394	$0 00076	-$0.00324	$0.00000	$0.00011	$0.12473	$0.00501	$0.00093	$0.00580	$0.00022	$0.00032	$0.00166	$0.00000		$0.00909	$0.16931	-14.3%
STANDBY																			
STANDBY T	35,609,987	$0.10914	$0 00851	$0 00076	-$0.00324	$0.00000	$0.00025	$0.04407	$0.01543	$0.00093	$0.00580	$0.00019	$0.00032	$0.00390	$0.00000		$0.00841	$0.08533	-21.8%
STANDBY P	7,205,190	$0.33258	$0 00903	$0 00076	-$0.00324	$0.00000	$0.00026	$0.29108	$0.01825	$0.00093	$0.00580	$0.00019	$0.00032	$0.00390	-$0.03494		$0.00302	$0.29538	-11.2%
STANDBY S	1,828,750	$0.22911	$0.00535	$0.00076	-$0.00324	$0.00000	$0.00016	$0.16464	$0.01765	$0.00093	$0.00580	$0.00019	$0.00032	$0.00390	-$0.00044		$0.00859	$0.20461	-10.7%
TOTAL STANDBY	44,643,927	$0.15012	$0 00847	$0 00076	-$0.00324	$0.00000	$0.00025	$0.08887	$0.01597	$0.00093	$0.00580	$0.00019	$0.00032	$0.00390	-$0.00566		$0.00755	$0.12411	-17.3%
AGRICULTURE																			
AG-A	108,685,880	$0.28993	$0 02319	$0 00076	-$0.00324	$0.00000	$0.00011	$0.20389	$0.01746	$0.00093	$0.00580	$0.00024	$0.00032	$0.00188	-$0.00549		$0.01011	$0.25596	-11.7%
AG-B	243,933,451	$0.25380	$0 02319	$0 00076	-$0.00324	$0.00000	$0.00011	$0.16877	$0.01677	$0.00093	$0.00580	$0.00024	$0.00032	$0.00188	-$0.00051		$0.00993	$0.22494	-11.4%
AG-C	1 093,643,175	$0.13651	$0.02319	$0.00076	-$0.00324	$0.00000	$0.00011	$0 05409	$0.01479	$0.00093	$0.00580	$0.00024	$0.00032	$0.00188	-$0.00043		$0.00977	$0.10821	-20.7%
TOTAL AG	1,446,262,506	$0.16782	$0 02319	$0 00076	-$0.00324	$0.00000	$0.00011	$0 08469	$0.01532	$0.00093	$0.00580	$0.00024	$0.00032	$0.00188	-$0.00082		$0.00983	$0.13900	-17.2%
B-20 CLASS																			
B-20 FIRM T	3,757,803,397	$0.05642	$0 01857	$0 00076	-$0.00324	$0.00000	$0.00009	-$0 00093	$0.01371	$0.00093	$0.00498	$0.00023	$0.00032	$0.00156	-$0.00247		$0.00612	$0.04062	-28.0%
FPP T	302,585,201	$0.01469	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0 00220	$0.01255	$0.00093	$0.00000	$0.00000	$0.00000	$0.00000			$0.00000	$0.01567	6.7%
TOTAL	4,060,388,598	$0.05331	$0 01718	$0 00070	-$0.00300	$0.00000	$0.00008	-$0 00070	$0.01362	$0.00093	$0.00461	$0.00021	$0.00029	$0.00145	-$0.00228		$0.00567	$0.03876	-27.3%
B-20 FIRM P	4,436,294,933	$0.09805	$0 02112	$0 00076	-$0.00324	$0.00000	$0.00010	$0 03504	$0.01461	$0.00093	$0.00580	$0.00024	$0.00032	$0.00156	-$0.00070		$0.00651	$0.08303	-15.3%
FPP P	18,928,521	$0.03649	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.02310	$0.01345	$0.00093	$0.00000	$0.00000	$0.00000	$0.00000			$0.00000	$0.03747	2.7%
TOTAL	4,455,223,453	$0.09779	$0 02103	$0 00076	-$0.00323	$0.00000	$0.00010	$0 03499	$0.01460	$0.00093	$0.00578	$0.00024	$0.00032	$0.00156	-$0.00070		$0.00648	$0.08284	-15.3%
B-20 FIRM S	1,690,680,387	$0.10840	$0 02050	$0 00076	-$0.00324	$0.00000	$0.00010	$0 04121	$0.01517	$0.00093	$0.00580	$0.00024	$0.00032	$0.00156	-$0.00020		$0.00752	$0.09067	-16.4%
FPP S	98,486,278	$0.03998	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.02603	$0.01401	$0.00093	$0.00000	$0.00000	$0.00000	$0.00000			$0.00000	$0.04096	2.5%
TOTAL	1,789,166,665	$0.10463	$0 01937	$0 00072	-$0.00306	$0.00000	$0.00009	$0 04038	$0.01511	$0.00093	$0.00548	$0.00023	$0.00030	$0.00148	-$0.00019		$0.00711	$0.08793	-16.0%
B-20 T	4,060,388,598	$0.05331	$0 01718	$0 00070	-$0.00300	$0.00000	$0.00008	-$0 00070	$0.01362	$0.00093	$0.00461	$0.00021	$0.00029	$0.00145	-$0.00228		$0.00567	$0.03876	-27.3%
B-20 P	4,455,223,453	$0.09779	$0 02103	$0 00076	-$0.00323	$0.00000	$0.00010	$0 03499	$0.01460	$0.00093	$0.00578	$0.00024	$0.00032	$0.00156	-$0.00070		$0.00648	$0.08284	-15.3%
B-20 S	1,789,166,665	$0.10463	$0.01937	$0.00072	-$0.00306	$0.00000	$0.00009	$0 04038	$0.01511	$0.00093	$0.00548	$0.00023	$0.00030	$0.00148	-$0.00019		$0.00711	$0.08793	-16.0%
TOTAL B-20	10,304,778,716	$0.08145	$0 01923	$0 00073	-$0.00311	$0.00000	$0.00009	$0 02186	$0.01430	$0.00093	$0.00527	$0.00022	$0.00030	$0.00150	-$0.00123		$0.00627	$0.06636	-18.5%
SYSTEM	**48,841,028,955**	**$0.15508**	**$0.02793**	**$0.00075**	**-$0.00321**	**$0.00000**	**$0.00013**	**$0.07012**	**$0.01503**	**$0.00093**	**$0.00532**	**$0.00026**	**$0.00031**	**$0.00219**	**-$0.00581**	**$0.00037**	**$0.00999**	**$0.12430**	**-19.8%**

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S PHASE 1 PROPOSALS IN RESPONSE TO THE ASSIGNED COMMISSIONER'S SCOPING MEMO AND RULING

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December 13, 2021

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SUMMARY OF RECOMMENDATIONS

- The Commission should clarify the treatment of IOU shown resources in the PCIA;
- The Commission should eliminate unnecessary barriers to LSEs showing their local resources to the CPE;
- The CPE should expedite another all-source solicitation to procure additional local resources for 2023 and complete it by the time system and flexible requirements are finalized;
- The Commission should immediately modify the timeline for 2023 CPE procurement and required documentation to provide adequate information to affected LSEs and avoid overprocurement of system and flexible RA resources;
- If the CPE fails to meet the modified timeline, the Commission should consider a waiver of system and flexible RA penalties for LSEs with shortfalls resulting from the uncertainty created by CPE procurement of local RA; and
- Within Phase Three of the Implementation Track, the Commission must evaluate the effectiveness of the current CPE structure.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
PHASE 1 PROPOSALS IN RESPONSE TO THE
ASSIGNED COMMISSIONER'S SCOPING MEMO AND RULING

The California Community Choice Association[1] (CalCCA) submits these proposals in response to the *Assigned Commissioner's Scoping Memo and Ruling* (Scoping Memo), issued on December 2, 2021.[2]

I. INTRODUCTION

Decision (D.) 20-06-002 adopted a "hybrid" central procurement entity (CPE) framework for local Resource Adequacy (RA) in Pacific Gas and Electric Company (PG&E) and Southern California Edison Company's (SCE) service areas beginning with the 2023 RA compliance year.[3] Under this framework, load-serving entities (LSEs) in PG&E and SCE's territories will no longer receive local RA allocations. Instead, CPE will be required to meet the local RA obligations through its own procurement using all-source solicitations or through "shown"

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[1] California Community Choice Association represents the interests of 23 community choice electricity providers in California: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

[2] *Assigned Commissioner's Scoping Memo and Ruling*, Dec. 2, 2021 (Scoping Memo).

[3] *Decision on Central Procurement of the Resource Adequacy Program*, June 12, 2020 (D.20-06-002).

resources offered by LSEs who retain the system and flexible attributes of resources they have procured but use the local attribute to reduce the CPE's overall procurement requirement. The CPE can also defer procurement to the California Independent System Operator (CAISO's) backstop mechanisms if procurement costs are deemed unreasonably high.

On November 1, 2021, PG&E and SCE's CPEs submitted Annual Compliance Reports summarizing CPE procurement activity in 2021. SCE Advice Letter 4626-E, dated November 1, 2021, summarizes the contracts, including local RA purchases and self-showing agreements, shown in Attachment A-1.[4] Additionally, the Independent Evaluator Report indicates a small amount of unfulfilled monthly 2023 obligations likely to be filled in future request for offers (RFOs), and therefore, nothing has been deferred to the CAISO's backstop processes.[5] PG&E's Supplemental CPE Annual Compliance Report filed on November 19, 2021 shows aggregate CPE procurement for the 2023 and 2024 compliance years.[6] Total PG&E CPE procurement for 2023 is short of the 100 percent local RA requirement by roughly 4,000 to over 6,000 megawatts (MW) in some months. Total CPE procurement for 2024 is over 600 MW short of the 50 percent local RA requirement. It is not clear in the advice letter if the CPE will attempt to do more procurement to meet the local obligation or defer procurement to the CAISO's Capacity Procurement Mechanism (CPM) authority.

The Scoping Memo issued on December 2, 2021 establishes three phases of the Implementation Track of this proceeding. Phase One of the Implementation Track will consider

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4 *Central Procurement Entity Annual Compliance Report: 2021*, Southern California Edison Company (SCE), Nov. 1, 2021 (SCE Advice Letter 4626-E), Attachment A-1.

5 SCE Advice Letter 4626-E, Independent Evaluator Report at 31 (document page 70 of 98).

6 *Supplemental: Pacific Gas and Electric Company ("PG&E")Central Procurement Entity ("CPE") Annual Compliance Report*, Nov.19, 2021, Attachment 1.

modifications to the CPE structure and process and is scheduled to conclude by March 2022. The Scoping Memo outlines four issues within scope of Phase One, including:

- Implementation details of the "shown" resource component of the hybrid framework;
- Whether the CPE should be permitted to procure local resources outside of the annual all-source solicitation process set forth in D.20-06-002;
- Changes to the CPE timeline; and
- Whether modifications are needed to the requirements that PG&E and SCE (acting on behalf of their bundled load) bid their utility-owned generation and contracted resources into the CPE solicitation at their levelized fixed costs.[7]

Without understanding the source of the challenges faced by CPEs in meeting their full obligation, it is difficult to propose specific solutions. CalCCA first identifies these potential challenges that may exist under the current structure. Next, CalCCA identifies critical short-term issues that should be resolved and clarified to ensure the CPE and LSEs can meet their compliance obligations under the new CPE structure beginning with RA year 2023 compliance. Finally, CalCCA proposes the Commission establish a longer-term process to comprehensively review and consider wholesale modifications to the hybrid CPE framework in Phase Three of this proceeding considering the significant amount of unfilled local obligations documented in PG&E's Supplemental Advice Letter. In summary, CalCCA recommends:

- The Commission should clarify the treatment of IOU shown resources in the Power Charge Indifference Adjustment (PCIA);
- The Commission should eliminate unnecessary barriers to LSEs showing their local resources to the CPE;
- The CPE should expedite another all-source solicitation to procure additional local resources for 2023 and complete it by the time system and flexible requirements are finalized;

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[7] Scoping Memo at 3.

- The Commission should immediately modify the timeline for 2023 CPE procurement and required documentation to provide adequate information to affected LSEs and avoid overprocurement of system and flexible RA resources;

- If the CPE fails to meet the modified timeline, the Commission should consider a waiver of system and flexible RA penalties for LSEs with shortfalls resulting from the uncertainty created by CPE procurement of local RA; and

- Within Phase Three of the Implementation Track, the Commission must evaluate the effectiveness of the current CPE structure.

II. POTENTIAL ISSUES FACING THE CPE FRAMEWORK

It is clear challenges exist with the current framework given the large local procurement requirement left unfilled in the PG&E service area for 2023 and 2024. However, without understanding the full picture of the local RA procurement landscape, it will be difficult for parties to this proceeding to identify the issues that need to be solved. Additional information is required for parties to make informed proposals to improve the central procurement entity framework. Such information includes:

- The amount of local RA self-shown to the CPE, specifying resources shown for no compensation and those shown under the Local Capacity Requirement Reduction Compensation Mechanism (LCR RCM);

- The amount of local RA bid as a bundled product in the CPE solicitation;

- The amount of local RA procured by the CPE, specifying the amount procured through self-showings for no compensation, LCR RCM self-showing, and bids;

- The reasons for rejecting or withdrawing bids or self-showing offers for each category of procurement; and

- Of the resources not procured, the nature of the entity that currently controls the asset (*i.e.,* generator, LSE, marketer).

Without this information, it is impossible for parties to know and understand the source of the challenges with procurement in order to develop specific proposals. While stakeholders can speculate regarding the potential reasons underlying the significant CPE procurement shortfall, the range of potential causes implicate a range of solutions. Therefore, CalCCA's proposals below focus on improvements that could be made to address potential challenges impacting compliance beginning in RA year 2023. Possible challenges include:

- Non-IOU generators with local RA resources may prefer not to sell bundled RA into the RA CPE to maintain the ability to separately transact system RA in the bilateral market;
- Terms and conditions of CPE solicitation and self-showing requirements deter LSEs from participation;
- Low levels of compensation for local RA attributes under LCR RCM do not provide sufficient incentives to self-showing when balanced with the associated risks (*e.g.*, substitution requirement); and
- LCR RCM is not available to all resources and so the benefit of self-showing such a resource is diminished even further.

As a result of the CPE uncertainty, LSEs face immediate and significant challenges in securing their own system RA positions. As provided in D.20-06-002, system RA resources associated with local RA bid into the CPE will allocated to all LSEs in proportion to their load share.[8] With a roughly 50 percent CPE open position for 2023, a significant possibility exists that additional 2023 system resources could be allocated to LSEs if and when the CPE fills its local RA position. This makes planning 2023 system RA procurement impossible for LSEs, leaving them between the rock and hard place of overprocurement or risking penalties. This position is untenable and must be addressed in the near term.

With these concerns in mind, CalCCA offers preliminary proposals in these comments. Additional opportunity for comments and revisions to proposals, however, will be critical as additional information on the failure of the PG&E CPE is brought to light.

[8] D.20-06-002, Ordering Paragraph 8.c. at 94.

III. PROPOSALS

A. The Commission Should Clarify the Treatment of IOU Shown Resources in the PCIA

The Commission addressed cost recovery for IOU resources offered to the CPE in D.20-06-002. The costs of IOU resources normally recovered through PCIA are instead recovered through CAM if the resource is bid and selected in the CPE solicitation; the CAM recovery lasts for the term of the CPE procurement commitment to the resource.[9] If a PCIA resource is not selected through the solicitation but instead is shown for local RA purposes, however, the Commission provided: "[S]hown resources are still subject to the local PCIA benchmarks adopted in D.19-10-001, which provide an RA capacity offset to the PCIA charge."[10] CalCCA seeks clarification of the Commission's conclusion for shown PCIA resources.

Benchmarks are applied in the PCIA for the purpose of "pricing" resource attributes retained for bundled customer use. If a resource is shown for local RA, rather than bid to the CPE, the IOU likely has retained the resource to use as system RA for its bundled customers. If bundled customers retain the resource for system RA use, the appropriate "price" for retention is the system RA benchmark, rather than the local RA benchmark.

B. The Commission Should Eliminate Unnecessary Barriers to LSEs Showing their Local Resources to the CPE

The current process for LSEs to self-show resources for local RA could result in a "one-size fits all" approach that in some cases, prevents LSEs from being able to self-show resources. Stringent requirements set by the CPE can result in significant revisions to existing contracts LSEs have with local resources that either put unnecessary risk on the LSE or require

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9 D.20-06-002 at 48.
10 D.20-06-002 at 77.

information about resource attributes that LSEs do not have and is unnecessary for execution of an RA contract. Due to the confidentiality requirements imposed by the CPEs during the CPE processes, LSEs are not at liberty to share the details of the requirements and/or terms and conditions that may have deterred completion of a self-showing; neither are generators or marketers at liberty to share their concerns regarding bid requirements.

The Commission thus should neutrally review and compare the bid and self-showing requirements and the contracts employed by each CPE to determine if certain requirements unnecessarily inhibit LSEs from showing local resources. In the event one CPE was able to secure significantly more self-shown resources than another, the Commission should identify discrepancies between each CPEs requirements to determine which are most prohibitive and assess whether those requirements are necessary.

C. The CPE Should Expedite Another All-source Solicitation to Procure Additional Local Resources for 2023 and Complete it by the Time System and Flexible Requirements are Finalized

Under the current CPE structure, CPEs are permitted to conduct multiple solicitations per year.[11] A second all-source solicitation should be performed quickly to meet the CPE's requirements by the time system and flexible requirements are finalized in June 2022. This solicitation must complete within the timeline outlined in section D so that (a) LSEs are aware of procurement done on their behalf by the CPE, and (b) the CAISO will know how much procurement may be deferred to its backstop authority in advance.

Given the magnitude of unfilled requirements for 2023, it is prudent for CPEs to perform additional solicitations early in 2022. This process should include another opportunity for LSEs

[11] D.20-06-002 at 38.

to self-show their own local resources after unnecessary barriers, if any, are eliminated so that LSEs can reach reasonable agreements with the CPE to self-show their resources.

D. The Commission Should Immediately Modify the Timeline for 2023 CPE Procurement and Required Documentation to Provide Adequate Information to Affected LSEs and Avoid Overprocurement of System and Flexible RA Resources

The intent of the present timeline was for the CPE to complete procurement in October two years prior to the operational year (*e.g.* October 2021 for RA year 2023).[12] The CPE timeline must provide sufficient time to allocate the system and flexible RA attributes as necessary and inform LSEs of their obligations prior to commencing final procurement for 2023 needs. Information around what has been procured by the CPE is critical for LSEs to plan their own system and flexible RA procurement because LSEs receive system and flexible credits for procurement done on their behalf by the CPE. Therefore, this information must be available to LSEs prior to the start of their own procurement for LSEs to plan effectively.

LSEs will begin procurement of 2023 system and flexible RA soon, if they have not already; having those solicitations compete for the same resources that the CPE is attempting to procure will result in overprocurement and increased rate-payer costs since procurement by either entity is likely to limit or eliminate the need of the other procuring entity. For these reasons, as a general matter, the CPE should complete their procurement of any local RA allocated to LSEs by October two years prior to the operational year, as intended. However, given the current circumstances, the timeline for 2023 procurement should be modified to allow time for expedited additional procurement to take place to meet the 2023 PG&E local area needs.

To enable LSEs to meet their system and flexible RA requirement without overprocurement and subsequent ratepayer costs and avoid distorting the market with CPE and

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12 D.20-06-002 at 69-70.

LSEs chasing the same resources, the CPE must complete its procurement from its additional all-source solicitation and put forth the results by the beginning of June 2022.[13] This leaves LSEs five months to complete their procurement of system and flexible RA with enough time to meet their obligations by October 2022. In addition, the Commission should require CPEs to provide additional information in an updated compliance report, specifying allocations of system and flexible RA to each LSE as a result of the incremental procurement and whether any of the resources procured in the first or supplemental solicitations extend beyond 2024. This information should be provided immediately following the conclusion of its procurement in June 2022.

The Commission must also recognize that the timelines for procurement impact not only the Commission's RA process but the CAISO backstop procurement process as well. As such, the Commission should work with the CAISO to ensure that both processes serve customers and grid reliability in the best manner. At the conclusion of the year-ahead RA showing, the CAISO will evaluate for local RA deficiencies. While an LSE may show a resource that is in a local area for their system or flexible RA needs, it is not clear that this will be satisfactory for the CAISO to consider that resource as meeting the local area needs and whether the CAISO would still backstop. Since only resources shown for local RA incur a requirement to be shown in the monthly showings, it is possible that a year-ahead showing of a system resource that is also located in one of the local areas may not show up in the month-ahead showing for that same month as the LSE may use another resource to meet their system or flexible RA need. Given this, the Commission and the CAISO need to determine the conditions under which the CAISO will conduct backstop procurement.

[13] The CPE could continue to accept self-showings beyond June 2022 until RA showings are due, as self-showings do not impact LSE allocations.

The Commission should also note that such backstop by the CAISO will occur after the annual showing but potentially before the month-ahead showing. While allocations by the CAISO could possibly happen in the monthly process, they would not happen at the time that year-ahead showings are due. This could result in LSEs either not meeting their year-ahead requirement or potentially being significantly over-procured at significant cost to customers. Since the quantity of backstop could be up to the currently short position of the CPE, the backstop could exceed 6,000 MWs. This is a significant uncertainty for all LSEs in conducting procurement.

Finally, if the local resources are under contract to an LSE for use in their system or flexible showings, they are unlikely to be sold to the CAISO for backstop purposes. This is because when the CAISO performs backstop, it buys all attributes. Thus, the LSE will not be able to offer the resource to the CAISO if doing so will make them short for their system and/or flexible RA requirements. For all these reasons, it is critical that the Commission include the CAISO in this process to determine how the various requirements and processes interact.

1. CPE Timeline

To fill remaining procurement requirements, as well as provide more certainty to LSEs procuring system and flexible RA, the following timeline should be adopted for 2023 procurement. This timeline generally follows the timeline outlined in D.20-06-002 with modifications to identify the timeline for additional CPE procurement that will provide LSEs with enough time to estimate the amount of procurement done on their behalf, the system and flexible RA credits they will receive as a result of CPE procurement, and the amount of procurement deferred to CAISO backstop authority.[14]

[14] Modifications to the existing timeline outlined in D.20-06-002 are underlined.

<u>February – May 2022:</u>

- <u>CPE conducts additional all-source solicitations for 2023</u>.

April-May 2022:

- The CAISO files draft and final local capacity requirement (LCR) one- and five-year ahead studies. LCR studies will include any CAISO-approved transmission upgrades from the Transmission Planning Process (TPP) LCR study.

- LSEs in SCE and PG&E TAC areas commit to CPE to show self-procured local resources in RA filing for 2023 and 2024.

- Parties file comments on draft and final LCR studies.

June 2022:

- The Commission adopts multi-year local RA requirements for the 2023-2025 compliance years as part of its June decision.

- CPE receives total jurisdictional share of multi-year local RA requirements for 2023-2025 compliance years.

- <u>CPE completes all-source solicitations for 2023 and submits updated compliance report documenting the information outlined in section 2, including the MW of resources offered to the CPE, the MW of resources accepted by the CPE, the rationale for the inability to accept any offers that were not accepted, and the amount of procurement the CPE expects to defer to backstop procurement.</u>

July 2022:

- For the SCE and PG&E TAC areas, LSEs receive initial RA allocations, including CAM credits and system, flexible, and local requirements for 2023 (but are not allocated local requirements for 2024 and 2025).

- For SDG&E TAC area, LSEs receive initial RA allocations (system, flexible, local requirements) and CAM credits.

Late September 2022:

- CPEs and LSEs that voluntarily committed local resources to the CPE make local RA showing to the Commission and the CAISO.

Late September/early October 2022:

- For PG&E and SCE's TAC areas, LSEs are allocated final CAM credits (based on coincident peak load shares) for any system and flexible capacity that was procured by the CPE during the local RA procurement process or by the CAISO through its RMR process.

End of October 2022:

- LSEs in the SDG&E TAC make system, flexible, and three-year local RA showing. LSEs in PG&E and SCE TAC make year-ahead system and flexible RA showing. The CAISO determines necessary backstop procurement.

2. Required Documentation

Under this timeline, after the CPE concludes procurement for 2023, the CPE should be required to file an updated Compliance Report documenting the same information identified above in Section II. In addition, the CPE should be required to specify the amount of system and flexible RA associated with the procurement that will be allocated to LSEs and whether any of the resources procured in the first or supplemental solicitations extend beyond 2024. The SCE CPE largely provided this information in its Annual Compliance Report.[15] This new information should be provided in the updated compliance report and continue to be provided in compliance reports for future years. LSEs and the CAISO would benefit from this additional transparency in advance to assess the status of CPE procurement efforts. LSEs need to be able to forecast the amount of system and flexible credits expected from CPE procurement in order to plan their own procurement. Additionally, LSEs would benefit from information about the CPE's intent to defer procurement to the CAISO as the backstop authority as LSEs are subject to backstop credit and costs.

[15] SCE Advice Letter 4626-E.

Further, the CPE should provide the reason behind any procurement deferred to the CAISO backstop, especially if the CPE forgoes procurement of a significant portion of the local obligation. If a CPE defers to the CAISO CPM authority, without understanding why the CPE deferred to the CAISO's backstop authority, it is unclear whether resources will be available to the CAISO to CPM and if the CAISO backstop mechanisms will be able to procure and allocate to fill the need under a relatively short timeframe. For example, if the CPE deferred to the CAISO backstop because bids into the CPE's solicitation were unreasonably high, the CAISO may be able to CPM local resources to meet the requirement. However, if the CPE deferred to CAISO backstop because not enough resources were offered into the solicitation, the CAISO may not be able to CPM local resources to meet the requirement because resources are being used to meet other obligations. This is critical because unlike the CPUC self-showing option where an LSE can retain the system and flexible RA value for their own needs, the CAISO CPM procures all attributes meaning that an LSE can only offer a resource in the CAISO CPM if they have sufficient resources without the resource offered to meet their own system and flex RA needs.

Requiring greater transparency around CPE procurement efforts would provide LSEs, the CAISO, and other stakeholders the ability to assess and understand how the current CPE structure is functioning. This assessment is required to determine if the current structure will result in sufficient procurement of local resources to maintain system reliability and whether it will place significant pressure on CAISO backstop mechanisms with relatively little time for such procurement and allocation to occur. While a review of existing confidentiality provisions may be necessary to determine if they are sufficient to protect confidential information related to

CPE procurement,[16] adequate public information is key for all parties to understand the local RA procurement landscape.

E. If the CPE Fails to Meet the Modified Timeline, the Commission Should Consider a Waiver of System and Flexible RA Penalties for LSEs with Shortfalls Resulting from the Uncertainty Created by CPE Procurement of Local RA

While the modifications proposed in Section D would provide LSEs the ability to more closely estimate the procurement performed on their behalf and system and flexible RA credits they can expect to receive resulting from procurement, significant uncertainty remains around if the CPE will be able to meet their full procurement obligation by the June timeframe. This impacts the amount of system and flexible RA LSEs will need to procure. If the CPE does not meet its full local RA obligation by June 2022, the Commission should consider waiving system and flexible RA penalties for LSEs whose procurement was impacted by CPE procurement shortfalls. The uncertainty created by the failed CPE procurement impacts LSEs' ability to comply with their procurement requirements. While the CPE does not face RA penalties for deferring procurement to CAISO's backstop authority, LSEs face penalties of up to $26.64/kW-month under the tiered penalty structure adopted in D.21-06-029. Given the uncertainties with CPE procurement for 2023, when assessing penalties for system and flexible RA deficiencies, the Commission should consider the role that the failed CPE procurement played in the ability of LSEs to procure resources given the uncertainty around the amount of system and flexible credits they will receive from CPE procurement.

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16 *Comments of Pacific Gas and Electric Company (U 39 E) On The Order Instituting Rulemaking To Oversee The Resource Adequacy Program,* Nov. 1, 2021.

F. Within Phase Three of the Implementation Track, the Commission Must Evaluate the Effectiveness of the Current CPE Structure

Progress made on CPE procurement thus far has highlighted challenges with the hybrid framework adopted in D.20-06-022, calling into question its effectiveness into the future. Indeed, the CPE efforts for 2023 have resulted in the procurement of *less than half* of the requirement in some months. Within the current CPE contracts, the provider of a self-shown resource takes on risk if the resource experiences an outage in a month shown during the annual RA showing. Without sufficient understanding of such risks, including indemnifications and consequences of CPE contract termination, parties may be hesitant to enter into such an agreement.
The LCR RCM is at most $1.78/kW-month, [17] indicating only a small premium for local resources. Further, the LCR RCM is not available to all resources, diminishing the benefit of showing those resources to the CPE even further. To mitigate against this uncertainty, LSEs are unlikely to offer local resources to the CPE if they risk being unable to meet their system obligation, especially if the solicitation process remains cumbersome and unlikely to reach reasonable agreements for self-showing.

The Commission must perform a comprehensive review of the CPE framework within Phase Three of the Implementation Track to consider whether wholesale modifications to the CPE framework is warranted. CPE was designed in an environment in which local was constrained and system was not significantly constrained, leading to the assumption that local would be at a premium to system resources. With the changes in those assumptions, the Commission should investigate whether the circumstances leading to the conclusion that CPE was necessary are still relevant. The Commission should examine whether the current scarcity of

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[17] See Local Capacity Requirement Reduction Compensation Mechanism: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/lcr-rcm-prices.pdf.

both system and local are better addressed by LSE based procurement or by shifting the CPE framework to a residual model as contemplated by the parties in the CPE settlement that was ultimately rejected in favor of the hybrid structure. Considering such changes in Phase Three will allow the Commission and parties to evaluate the effectiveness of the CPE following the first year of RA compliance under the hybrid structure.

IV. CONCLUSION

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

Respectfully submitted,

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING DIRECTING FURTHER PARTY COMMENT, REQUESTING PARTY PROPOSALS, AND AMENDING PROCEDURAL SCHEDULE

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SUMMARY OF RECOMMENDATIONS

- ✓ The Provider of Last Resort (POLR) service should be limited to 60 days to allow returned customers to transition from the returning load-serving entity (LSE) to the customer's chosen LSE, consistent with the existing "safe harbor" provision for Direct Access (DA) switching;

- ✓ Given the limited term and scope of service and the need to avoid unnecessary costs, the POLR should not engage in advance procurement or hedging;

- ✓ Renewable Portfolio Standard (RPS) and Integrated Resource Planning (IRP) responsibility for returned customers should shift directly from the returning LSE to the customer's new LSE, with a waiver of these obligations for the POLR consistent with the existing waiver for Resource Adequacy (RA) obligations adopted in Decision (D.) 20-06-031;

- ✓ The Commission should compare Reentry Fees and actual costs for Western Community Energy's (WCE) customer return to determine whether the current formulation provides sufficient precision to ensure a reasonable outcome;

- ✓ A POLR right of first refusal (ROFR) of procurement contracts held by the returning LSE raises legal and commercial issues and should not be considered;

- ✓ To minimize the risk of LSE default by newly launched community choice aggregators (CCA), Implementation Plan requirements should be modified to incorporate a milestone procedure to be administered by the CCA's governing board, quarterly updates to Energy Division on the status of milestone achievement, transparency through the use of a publicly available information portal available, and feasibility studies provided to the local governing board built on transparent and standardized referents; and

- ✓ Financial service requirements (FSR) should vary with the financial health of an LSE, limiting FSRs for LSEs maintaining investment-grade credit ratings and LSEs voluntarily providing limited metrics to the Commission for review; all other LSEs should bear responsibility for the currently formulated FSR.

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

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

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING DIRECTING FURTHER PARTY COMMENT, REQUESTING PARTY PROPOSALS, AND AMENDING PROCEDURAL SCHEDULE**

The California Community Choice Association[1] (CalCCA) submits these Comments in response to the *Administrative Law Judge's Ruling Directing Further Party Comment, Requesting Party Proposals, And Amending Procedural Schedule* (Ruling), issued on November 23, 2021.

I. INTRODUCTION

Senate Bill (SB) 520[2] establishes requirements for the California Public Utilities Commission (Commission) and the POLR, whether the POLR is an investor-owned utility (IOU) or a non-IOU party. In this phase, the Commission is reviewing and considering revisions to the POLR rules as they apply to the IOUs. The Ruling thus seeks comments on specific features of

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[1] California Community Choice Association represents the interests of 23 community choice electricity providers in California: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

[2] Cal. Pub. Util. Code § 387.

the existing framework for the involuntary return of customers to the IOU, such as deregistration, financial security requirements, and reentry fees. CalCCA provides comments on these specific features below in response to the questions posed in the Ruling. The Commission's efforts to resolve these and other questions, however, are best served by grounding the discussion in a clear definition of POLR and guiding policy principles.

The Commission should consider the POLR definition proposed by Southern California Edison Company's (SCE) in its comments in this Order Instituting Rulemaking (OIR). SCE equates the POLR function to the "safe harbor" service the IOUs provide today for returning DA customers. Adopting this definition limits the amount of planning and procurement the POLR must undertake to fulfill its role. As discussed below, however, it raises other issues, such as the separate needs of the default service provider (DP), the length, scope, and purpose of the FSR, and the rules for customer return to utility bundled service when no POLR service is required.

In addition to refining the POLR definition, the Commission should adopt guiding policy principles to shape the stakeholder discussion. CalCCA proposes the following principles:

- All customers – bundled and unbundled alike – should be protected from unnecessary or duplicative costs when a LSE involuntarily returns customers to the IOU for POLR service;
- The POLR should provide only a short-term service bridging any transition of the returned customers to DP service or the service of another LSE;
- All customers that have an alternative LSE to the DP should be able to exercise that alternative before or during the term of POLR service;
- As a short-term service provider, the POLR should not bear responsibility for meeting the state's longer term goals; and
- The rules adopted in this phase of the OIR should be sufficiently durable to accommodate consistency of POLR requirements across both phases regardless of the identity of the POLR.

With the proposed POLR definition and principles in mind, CalCCA offers the following proposals in these comments:

- ✓ POLR service should be limited to 60 days to allow returned customers to transition from the returning LSE to the customer's chosen LSE, consistent with the existing "safe harbor" provision for DA switching;
- ✓ Given the limited term and scope of service and the need to avoid unnecessary costs, the POLR should not engage in advance procurement or hedging;
- ✓ RPS and IRP responsibility for returned customers should shift directly from the returning LSE to the customer's new LSE, with a waiver of these obligations for the POLR consistent with the existing waiver for RA obligations adopted in D.20 06-031;
- ✓ The Commission should compare Reentry Fees and actual costs for WCE's customer return to determine whether the current formulation provides sufficient precision to ensure a reasonable outcome;
- ✓ A POLR right of first refusal (ROFR) of procurement contracts held by the returning LSE raises legal and commercial issues and should not be considered;
- ✓ To minimize the risk of LSE default by newly launched CCAs, Implementation Plan requirements should be modified to incorporate a milestone procedure to be administered by the CCA's governing board, quarterly updates to Energy Division on the status of milestone achievement, transparency through the use of a publicly available information portal available, and feasibility studies provided to the local governing board built on transparent and standardized referents; and
- ✓ FSR requirements should vary with the financial health of an LSE, limiting FSRs for LSEs maintaining investment-grade credit ratings and LSEs voluntarily providing limited metrics to the Commission for review; all other LSEs should bear responsibility for the currently formulated FSR.

Modifying the POLR consistent with these recommendations will protect bundled customers from cost shifts while avoiding unnecessary, duplicative costs.

Finally, CalCCA seeks clarification of a key issue for CCAs. In some cases, the need for POLR service to returned CCA customers could be averted if another LSE is willing to step in to serve the customers. For example, there may be opportunities for a CCA Joint Powers Authority (JPA) to absorb a financially challenged CCA before the latter resorts to returning customers to the POLR. Enabling these types of transitions gives CCA customers, like DA customers, an opportunity to select a non-IOU to provide ongoing service. CalCCA thus seeks clarification that no advance Commission certification is required, assuming local governing board approvals and notices (1) for an existing JPA to absorb an existing CCA, or (2) for two existing CCAs to form a new JPA. As discussed below, the current implementation plan procedures are built around mitigating the impacts of CCA customer departure on bundled customers, and neither of these transactions risk bundled customer impacts.

II. POLR SERVICE SHOULD BE DEFINED AS A 60-DAY "SAFE HARBOR" SERVICE CONSISTENT WITH EXISTING DA SWITCHING RULES

California Public Utilities Code § 387(a)(3) defines "provider of last resort" as follows:

> a load-serving entity that the commission determines meets the minimum requirements of this article and designates to provide electrical service to any retail customer whose service is transferred to the designated load-serving entity because the customer's load-serving entity failed to provide, or denied, service to the customer or otherwise failed to meet its obligations.

While the statute provides a starting point, the Commission should establish a clear boundary between the roles of the IOU as POLR and the IOU as a DP. Although the safe harbor was conceived in the context of DA voluntary switching rules, SCE's recommendation to look to the existing 60-day "safe harbor" service as the demarcation point between POLR and DP service merits consideration. Adopting this approach, however, raises a number of additional questions that must be answered related to the application of the FSR between the two services and the terms and conditions of DP service.

SCE "finds no justification for expanding the IOU POLR safe harbor beyond its current 60 days."[3] SCE explains "how thoughtful the Commission was in resolving the question of the 'temporary' safe harbor's duration"[4] in D.03-05-034. In that case, long before the first CCA launched, the Commission's thoughts centered on providing the DA customer enough time to switch Electric Service Providers (ESPs).[5] In most cases, as SCE notes, 60 days gives those customers sufficient time to switch to a new ESP or elect to return to bundled service.

The same concept should work for CCAs and could, in some circumstance, defer the need for POLR service for a financially challenged CCA ***if*** another CCA JPA wishes to absorb the challenged CCA. CalCCA thus seeks Commission clarification of its rules as they apply to CCAs' "switching" opportunities. If the existing CCA implementation plan process of a year or more applied to CCA-switching, the safe-harbor DA switching rules may not be suited; it would be infeasible under those circumstances to transition either to defer POLR service or within the 60-day safe harbor period to follow POLR service. CalCCA submits, however, that the existing implementation plan process does not apply to circumstances in which a CCA JPA absorbs a financially challenged CCA. Assembly Bill (AB) 117 required implementation plans to mitigate potential effects on IOU bundled customers when a community decides to aggregate load and form a CCA to provide service.[6] CalCCA thus requests clarification that absorption of a

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3 *Reply Comments of Southern California Edison Company (U 338-E) on the Proposed Order Instituting Rulemaking to Implement Senate Bill 520 and Address Other Matters Related to the Provider of Last Resort* (SCE Reply Comments) at 5.

4 SCE Reply Comments at 3.

5 *Id.* at 2 (*quoting* D.03-05-034 at 22-23 ("The safe harbor is not intended as a place to be used to shop around among different ESPs while taking bundled service and delaying submission of a DASR. The safe harbor provision is intended to facilitate an already contemplated switch to a new ESP.")).

6 *See* California Public Utilities Code § 366.2(c)(3) (requiring an implementation plan for CCA formation); *see also* California Public Utilities Code § 366.2(c)(5) requiring an implementation plan to determine cost responsibility to avoid cost shifts to bundled customers).

financially challenged CCA by an existing CCA JPA and other transactions that do not involve IOU departing load are ***not*** subject to the one-year implementation planning process. With this clarification, CalCCA supports SCE's proposed 60-day POLR service.

III. GUIDING PRINCIPLES

To guide the stakeholder discussion and Commission decision-making, CalCCA recommends adoption of several guiding principles.

1. *All customers – bundled and unbundled alike -- should be protected from unnecessary or duplicative costs when an LSE involuntarily returns customers to the IOU for POLR service.*

Affordability is one of the Commission's top priorities, currently being addressed in Rulemaking (R.) 18-07-006. Mitigating the costs of involuntary customer returns likewise should minimize impacts on affordability. An involuntary return of customers should not shift costs to IOU bundled customers. The Commission must also consider, however, potential rate impacts on unbundled customers. POLR rules must be designed to minimize unnecessary or duplicative costs that could fall on unbundled customers.

2. *The POLR should provide only a short-term service bridging any transition of the returned customers to default provider service or the service of another LSE.*

The POLR should not be viewed as an LSE but rather a short-term transitional role for customers returned to the IOU by a financially challenged LSE, consistent with the current DA switching rules.[7] The focus should be on transitioning customers to a default provider or an alternate LSE, as quickly as possible so that the latter may assume full responsibility for meeting reliability and climate obligations on the customer's behalf.

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[7] *See* D.03-05-034

3. *All customers that have an alternative LSE to the DP should be able to exercise that alternative before or during the term of POLR service.*

All customers returned to the IOU for POLR service by another LSE should have comparable options to "switch" providers before or during the POLR period. The nature of the returning LSE should not foreclose a customer's opportunity to switch.

4. *As a short-term service provider, the POLR should not bear responsibility for meeting the state's longer term goals; the responsibility should remain with LSEs.*

All LSEs have the primary responsibility for serving the needs of their customers. This includes the provision of energy, capacity for reliability (including both RA and resources necessary to meet the IRP-identified needs), renewable attributes, and green-house gas reduction. The POLR rules should not change this dynamic nor interfere with or complicate existing programs. Retaining these obligations in the non-POLR LSEs will help limit unnecessary or duplicative costs to returned customers.

5. *The rules adopted in this phase of the OIR should be sufficiently durable to accommodate consistency of POLR requirements regardless of the identity of the POLR.*

Phase 2 of this proceeding will consider, consistent with SB 520, allowing entities other than the IOUs to serve as POLR. The Commission thus should avoid any decisions in this Phase that would inhibit another entity from serving as the POLR at the outcome of Phase 2. Likewise, the requirements for the IOU should be no less stringent than would be required for a non-IOU serving in this regulated role.

IV. BUNDLED AND UNBUNDLED CUSTOMERS ALIKE SHOULD BE PROTECTED FROM COST SHIFTS AND UNREASONABLE COSTS

The POLR rules should protect all customers from unnecessary costs – both bundled and unbundled customers alike. The Commission has sufficiently addressed the need to avoid cost shifts from returned customers to IOU bundled customers through the FSR and Reentry Fees. It should equally focus on avoiding unnecessary and duplicative charges to returning customers in the POLR process.

Returning customers would be at risk for unnecessary or duplicative costs if a POLR were required to engage in advanced procurement, as discussed below in response to question D.2. By shortening the term of POLR service and limiting the scope of POLR procurement, as proposed in these comments, the Commission will help ensure all POLR costs are reasonable.

As will be further discussed in section VI, question B.1, while hedging as considered in this proceeding (*i.e*. FSR and POLR procurement of resources in anticipation of an LSE failure) are viewed as desirable to protect bundled load from the unanticipated return of customers when market prices may be high, the discussion should also consider how such hedging mechanisms work with other mechanisms and the costs that POLR actions would entail as well as who will pay for such costs. It is not just the protection of bundled customers that should be considered but the protection and fair treatment of all customers including the risks and costs of all mechanisms considered. In fact, if the POLR is hedging with instruments used only when a default by an LSE occurs, that hedge does nothing for the LSE to avoid a default and will mean that the LSE will hedge that risk as well. With the cost of the POLR hedge likely to be borne by the CCA customer as well as the hedge put in place to prevent the risk of failure by the CCA, the CCA customers will hedge and pay twice. Once to mitigate the market price risk and a second time to mitigate the risk to bundled load customers. However, these hedges are duplicative since the hedge entered by the CCA to mitigate market price risk is designed also to mitigate the risk that the CCA itself fails. It is this same market risk of failure that the POLR hedge is designed to address and is therefore duplicative.

With respect to Guiding Principle #1 in section III, the Commission should evaluate the need for, methods of, and equity of hedging currently in place to protect all customers given the cost of hedging. Hedging in this sense is primarily considered as an energy product. Energy hedging can take a number of forms but most commonly includes call option contracts, fixed price energy, and tolling agreements. In both the call option and fixed price energy arrangements, a buyer will receive energy at a specified price. With the call option, the buyer has the option to strike the agreed upon price or not, at the buyer's discretion. The fixed price energy arrangements provide no option and will simply deliver during the agreed upon time period at the agreed upon price. Tolling agreements, on the other hand, effectively allow a buyer to lease a facility and operate it at their discretion while absorbing the costs as well as obtaining market revenues. When viewed from the buyer side, these mechanisms can mitigate exposure to high energy costs in the CAISO market. From the supplier side, they limit the ability to profit from those same market events. Therefore, in selling such an instrument, the seller must be convinced that the loss of potential market revenue is accounted for in the cost of the hedging product. This payment is generally referred to as a "premium" which is paid regardless of the use of the resource or the provision of energy. Hedging comes with a cost.

All LSEs have an incentive to hedge to protect their customers and mitigate their own financial exposure over time. The IOUs are regulated in their hedging strategies and implementation by the Commission. Each CCA's hedging strategy is appropriately determined by their Board of Directors as a procurement responsibility on behalf of their served communities.

In addition to hedging that a CCA will employ for its own needs, the CCA energy costs are also hedged though actions taken by the IOU. This comes in the form of the Power Charge

Indifference Amount (PCIA) and the Cost Allocation Mechanism (CAM). With regard to PCIA, the amount charged serves much like a fixed price energy contract in which the CCA customers will pay the cost of the IOU historical procurement less the revenues from the market. As such, the CCA will always pay no more than the total PCIA cost. When market prices go up, the PCIA that the CCA pays will go down and vice versa. This counteraction of the costs serves as a hedge to the total generation costs that will be paid by a CCA customer and therefore must be considered when a CCA enters into its own hedges. CAM similarly requires a CCA customer to pay for the cost of utility procurement and is offset by the market revenues of the energy the resource provides. CAM also allocates the RA and RPS (if applicable) to all customers while the PCIA establishes a value to credit against the costs. Both CAM and PCIA hedge the costs of CCA customers and are outside of the control of the CCA whose customers are impacted.

The FSR also hedges risk and while it has been theorized to hedge against volatile market prices, it is fundamentally a hedge for bundled load customers against the risk of returning load and how costs from those returning customers may impact the bundled customers rates. The risk of volatile energy prices is exacerbated for a CCA under the existing FSR rules. At a time of rapidly increasing market prices, a CCA will need to both serve customers in a more expensive environment and post an FSR that could increase to tens of millions of dollars to cover the same above market costs a second time. Such financial security has an associated cost and will be paid for by CCA customers even if the CCA never fails. The additional exposure created by the FSR has the potential to be the actual cause of a CCA failure at a time of high market prices. Thus, while the FSR protects bundled customers from price volatility, it exacerbates that same risk for unbundled customers. The Commission must consider the probability of a CCA default in the context of the FSR rules, rather than simply assuming 100 percent likelihood of failure and exacerbating the risk of market price volatility for all CCAs. As discussed further in section VI, question B.1, the Commission should employ a process where the use of hedging instruments by the POLR (e.g., FSR) is dependent upon the financial status of the retail access LSE. In addition, as discussed in section VI, question D.2, the POLR should not procure energy, renewable attributes, or capacity in anticipation of a potential failure as this is may include redundant procurement of energy, RPS, and RA resources. Doing so would place competition in the market for those resources which may end up being held by the POLR without any compliance obligations and unavailable for other LSEs with compliance obligations. Adding more competition to the market will increase prices, especially in constrained markets (e.g., RA).

In addition to such a mechanism adding upward pressure on market prices, the costs of such procurement would also need to be allocated and create a significant risk of undermining competition. Given the current designation of IOUs as POLRs, it appears reasonably certain that the IOU will not be sending their customers to POLR service for quite some time. California is unlikely to allow the entity serving as a POLR to cease to operate. This is supported and partly substantiated by the history of allowing PG&E or a replacement entity to continue service for bundled customers if PG&E becomes insolvent (*i.e.* recent PG&E bankruptcy proceeding including the enhanced oversight and enforcement process and SB 350 (2020) allowing for the creation of Golden State Energy). It will likely take years before another entity serves as the POLR. Thus, it is unlikely the POLR would need to provide service to bundled customers in the near-term. Therefore, the cost of procurement performed by the POLR in anticipation of an LSE failure is likely to fall only on unbundled customers, including those whose LSEs may be at *lower* risk of failure than the IOU. In favoring the IOU customers by virtue of the IOUs' status as the POLR, these costs will have a direct anticompetitive impact.

Consideration of actions from the POLR, including hedging, FSR, PCIA, and CAM, must be considered holistically since the impact of each element differs for each entity and could place burdens and obligations that are inappropriate without full consideration.

V. COMMENTS ON WORKSHOP 1

1. Please provide any additions, clarifications, or corrections to the October 29, 2021, Staff Workshop (Workshop 1) notes submitted by California Community Choice Association.

CalCCA supports the suggestion made in Workshop 1 to examine the affiliate transaction rules for applicability to avoid the risk of the POLR service artificially subsidizing bundled utility service.

2. Please provide any additional comments on issues raised in Workshop 1.

CalCCA does not offer any additional comments on the issues raised in Workshop 1.

VI. QUESTIONS REGARDING POLR FRAMEWORK

A. Registration, Deregistration, and Regulatory Compliance

1. Regarding California Public Utilities Commission (CPUC) procurement requirements, what if any changes or clarifications to the responsibilities of the Investor-Owned Utility (IOU) as Provider of Last Resort (POLR) and the deregistering Load Serving Entity (LSE) should be considered? How should any recommended changes or clarifications to the requirements be applied in the scenarios of both a sudden deregistration (ex: abrupt bankruptcy) and a planned de-registration with a long notice period (ex: 1 year)? For any proposed changes or clarifications, please address how they also maintain the integrity of the underlying procurement program and statutory objectives. Please address:

a. Resource Adequacy
b. Integrated Resource Plan (IRP)
c. Renewable Portfolio Standard
d. Any other procurement obligations?

Consistent with CalCCA's proposed guiding principle #4, the POLR should not bear responsibility for meeting the state's long-term goals, including IRP and RPS requirements.

All LSEs have the primary responsibility for serving the needs of their customers. This includes the provision of energy, capacity for reliability, and renewable attributes and achievement of targeted GHG emissions reductions. The POLR rules should not change or complicate administration of the already complicated IRP and RPS programs. Consistent with this approach, the Commission should automatically waive the IRP and RPS requirements for the POLR.

The IRP and RPS responsibilities should remain with the non-POLR LSEs. If the returning LSE has failed to meet the requirements of a procurement order or an RPS compliance showing on behalf of the returned customers, the Commission should employ any enforcement mechanisms available under those programs. Any future IRP and RPS requirements for returned customers should then be assumed by the LSE who assumes continuing service following the POLR service.

The POLR's responsibility for RA likewise should be limited considering the 60-day service term. Having the POLR meet any year-ahead RA obligations seems unnecessary since it will serve the returned load for only two of the twelve months. Month-ahead showings may or may not be feasible, depending on the timing of customer return relative to the showing required 45 days in advance of prompt month. Even if there is an ability to make the month-ahead showings, the Commission should maintain the RA waiver for the POLR adopted in D.20-06-031.

2. Panelists in Workshop 1 described challenges in ensuring customers are informed about Community Choice Aggregator (CCA) deregistration. Should the CPUC adopt customer notification requirements, and if so, what should those be? Please address how any proposed requirements would improve and ensure adequate:

a. Timing and frequency of communications

b. Format of communications (ex: mailers, email, call, text, website, other?)

CalCCA encourages the use of on-bill messaging for customer notifications about deregistration of a CCA that actively served customers. The customer bill is regularly used to communicate messages to customers and limits the need to incur additional marketing costs. This proceeding should endeavor to avoid creating additional costs associated with discontinuing an LSE's service. To do otherwise would create additional liabilities that may impair the position of creditors or customers. For example, if the deregistering CCA were required to send mailers to all customers, it may need to utilize limited financial resources that would have otherwise been available to pay a reentry fee, potentially leaving residual costs for customers to absorb. The timing and frequency of communications should allow for an emergency transition that may happen on a short timeline.

CalCCA also observes that customer notifications related to a CCA deregistration where a CCA never initiated service to customers is not needed. In such a case, the need for customer notifications is significantly diminished as the customers' existing service would not be changed. Additionally, the affected customers will continue to benefit from public notices and public meetings associated with local jurisdiction decision making around the CCA service.

3. What changes or updates, if any, are needed in the CCA registration process in light of Senate Bill (SB) 520?

CalCCA provides two recommendations aimed to help CCAs avoid the need for the POLR. First, the Commission should consider enhancing the implementation planning process, whether in this proceeding or another forum. Second, the Commission should clarify that there are no implementation plan requirements for an existing CCA to "absorb" a financially challenged CCA.

To avoid the need for POLR service, enhancement of the existing implementation plan procedures may be required.

- ✓ A milestone process should be developed and administered by the local governing board to ensure a ***new*** CCA is undertaking the due diligence necessary to launch; similar requirements will not be necessary for expansion of existing CCAs.
- ✓ The milestone procedure should require ***new*** CCAs to do a feasibility study employing a standardized set of price referents and should be required to update the study not less than six weeks before launch; other referents may also be used for additional studies at the discretion of the CCA.
- ✓ The Commission should require quarterly updates by the CCA to the Energy Division of milestone progress and an update, including a revised feasibility analysis, not less than six weeks prior to launch; and
- ✓ During the milestone process, the CCA should be required to maintain a standardized information portal available to the Commission in overseeing completion of key milestones.

While these measures may not prevent ill-timed launches, they should reduce the risk of failure upon implementation. The measures also will provide the Commission greater insight into the implementation process and enhance launch best practices. CalCCA has also undertaken the development of these measures internally to provide "best practices" to new CCAs.

In addition to these implementation measures, the Commission should clarify that no advance Commission certification is required, assuming local governing board approvals for an existing JPA to absorb an existing CCA or other similar transactions between existing CCAs. This clarification could enable CCA customers to continue to be served by an LSE rather than to default to POLR service or, possibly, to transition to a new CCA during the POLR service period. Confirming that these transactions may be done without certification will not impact IOU bundled customers, since they will result in no IOU departing load and thus no change in the load the IOU must serve. Indeed, for that reason, an existing DA customer receiving service from a failing ESP could switch to an alternative ESP without needing to get back in line for a DA allocation.

4. What changes, if any, are needed in the CCA de-registration process in light of SB 520? Please address:

a. How the de-registration process changes would be implemented in the event of a sudden deregistration

b. How the de-registration process changes would be implemented in the event of a planned deregistration

c. Timeline for notification to the CPUC, IOU, and the public of the deregistration

d. Roles and responsibilities between the IOU as POLR and LSE as to de-registration e. Any other issues regarding de-registration

As noted in the presentation from David Oliver during the October 29, 2021 POLR workshop, there is limited precedent to inform the process of deregistration of a CCA that is serving load. While not explicitly addressed in SB 520, CalCCA supports examining the framework for de-registration in the context of POLR rules. CalCCA has no specific recommendations at this time but looks forward to hearing the insights from SCE gained in the de-registration of WCE and Baldwin Park Resident Owned Utility District (Baldwin Park). Whatever the direction, however, CalCCA encourages the Commission to provide significant flexibility to accommodate the potential need to transition customers on an emergent basis and avoid mandating continued service by an insolvent provider.

B. Financial Security Requirements and Reentry Fees

1. Is the current methodology regarding financial security requirements and reentry fees adequate? If not, what changes or additional clarifying language is needed in order to implement the requirements of Public Utilities Code Section 394.25(e) requiring reentry fees to avoid shifting costs to bundled customers?

CalCCA generally supports the existing methodology for the FSR in that it considers both administrative and procurement costs and looks forward at six months of expected costs. However, CalCCA suggests revisions to the FSR and reentry fees to: (1) account for the new role of POLR as distinct from bundled service; and (2) consider the likelihood of an LSE to discontinue service.

First, the Commission should allocate the benefits of the FSR between the POLR and the LSE that will provide continuing service – whether a DP or another LSE. With the POLR role defined in statute, bundled customers will soon have an intermediary that will provide service to involuntarily returning customers and further shield bundled customers from costs. As such, the FSR should be modified so that it is available to the POLR for its 60-day service; the remaining four months of FSR coverage would inure to the benefit of the LSE that will provide ongoing service to the extent the customer has not provided at least six months' notice of return.

Second, the Commission should gauge the level of FSR required depending upon the risk of default presented by the LSE. The posting of security has a long history in many industries including the energy industry. The posting of credit or collateral is largely based upon the risk of failure of one or both parties to a transaction. The Edison Electric Institute's Standard Power Purchase Agreements indicate different collateral posting requirements based on risk of default and consider credit ratings in doing so. For circumstances in which it is highly unlikely that an entity will fail, it is not useful or logical for their customers to incur the costs associated with posting an FSR. The Commission's current approach strictly calculates the reentry fee to be equal to the FSR under the assumption that the Commission cannot determine when an LSE will fail.

Since this one-size-fits-all FSR was adopted, much has changed with respect to available and well-accepted information indicating financial health of a CCA. Indeed, at this time, six CCAs have obtained investment grade credit ratings:

CCA	*Moody's*	*S&P*	*Fitch*
MCE	Baa2	A	BBB+
Peninsula Clean Energy	Baa2		BBB+
Silicon Valley Clean Energy	Baa2	A	
Central Coast Community Energy		A	
CleanPowerSF	A2		
East Bay Community Energy		A	

While these ratings are not an absolute guarantee that a CCA will not at some time fail, they are a strong indicator of financial health determined by ratings analysts applying a wide range of metrics. CCAs with investment-grade credit rating should not be required to post financial security.

If an CCA does not have an investment-grade credit rating, it should still have an opportunity to avoid posting an FSR provided they are willing to provide certain financial metrics for Commission monitoring. Specific metrics could be set, and a CCA not meeting the metric would be required to post an FSR.

Absent either an investment-grade credit rating or willingness to permit the Commission to monitor metrics, a CCA would be required to post an FSR. CalCCA continues to support the existing FSR methodology for that purpose.

2. What if any alternative to the current FSR and reentry fee methodology should be considered that would achieve the goals of Public Utilities Code Section 394.25(e) more effectively?

In the wake of the WCE and Baldwin Park customer returns, the Commission should review the Reentry Fee calculation. The current Reentry Fee was developed with an eye toward administrative ease using averaged revenues and prices. While the need for a transparent, administratively simple approach is understandable, the recent returns offer an opportunity to examine how the Reentry Fee performed with respect to these customers. CalCCA suggests examining, with SCE's assistance, a comparison of the Reentry Fee with actual costs.

High-level review suggests that the seasonality in rates and costs may result in a Reentry Fee that diverges from actual costs. The difference in market prices across seasons may explain why the Reentry Fee for WCE was nearly $15 million dollars while the reentry for Baldwin Park showed that the combination of expected rate revenues and currently available FSR would fully recover the anticipated costs of the return.

Examining further the re-entry fee calculation, one can use line 34 (energy cost forecast) and line 28 (CCA usage forecast) within the SCE Advice Letters 4541-E (WCE Re-Entry Fee Calculation) and 4648-E (Baldwin Park Re-Entry Fee Calculation) to conclude that the energy price forecast was $79.04/MWh and $61.10/MWh respectively. This represents a 22.7 percent difference in forecast energy costs. At the same time, the average generation rate applied to determine expected revenues were $86.00 for WCE and $86.23 for Baldwin Park, representing only a 0.3 percent difference in expected generation revenues. If the actual retail rates charged reflect a similar split in summer and winter generation charges, the use of an annual system average generation rate while using a forecast of energy costs for the actual period of re-entry fee service will result in a significant discrepancy.

Similarly, the FSR calculation should consider anticipated IOU rate changes that are likely to be in effect during the posting of that FSR. For example, the November 10, 2021 advice letter filed by the IOUs should reflect proposed changes to bundled rates that are likely to be in effect the first six months of the next year. This change will reduce the likelihood of a discrepancy between a posted FSR and a calculated reentry fee.

C. Costs of POLR Service

If the POLR must do advance procurement or a significant level of procurement during a major market event, the POLR may incur costs that exceed the reentry fees paid by the LSE.

1. **If an electric IOU, as the statutorily designated POLR, incurs such additional costs, should these additional costs be shared and recovered from all ratepayers within the IOU service territory pursuant to Public Utilities Code Section 387(g)? If so, what changes, if any, should be considered to the current regulatory requirements? If not, why not?**

Differences between the FSR/Reentry Fee and actual costs, if any, must be handled in a balanced way. If the POLR incurs costs above the FSR/Reentry Fee, the POLR should look to the returning LSE to the extent funds are available. If the POLR incurs costs below the FSR/Reentry Fee, the POLR should credit the excess fee back to the customers directly.

Reasonable and modest additional costs that cannot be recovered from the FSR/Reentry Fee should be recovered only from the customers taking service from the POLR. Consistent with the principles of cost causation, the customers receiving POLR service should generally be responsible to cover the cost of providing that service. This is particularly true in times of relative market instability. The POLR rules would need to provide, however, that the newly serving LSE would be responsible for collection of those costs from returning customers.

D. Continuity of Service

LSEs play a crucial role in maintaining system reliability. While the IOU s as POLRs may be able to absorb individual or small CCA failures, the failure of larger LSEs, or the possibility of multiple concurrent LSE failures due to a major market shortage may be infeasible for the IOU as POLR to absorb during tight market conditions.

1. **What types of mechanisms or requirements should be considered to ensure that the POLR has access to procurement resources in the event of large or multiple LSE failures? Please address the following:**

    a. **Should a right of first refusal provision in LSE procurement contracts be included to ensure the IOU as POLR can choose to assume such procurement contracts if needed?**

No, a POLR ROFR should not be considered. Providing a ROFR to the POLR for a long-term contract simply does not make sense given the POLR's 60-day service obligation. In addition, a POLR ROFR raises serious legal and commercial concerns.

As discussed above, and posited earlier in the proceeding by SCE, the POLR term of service is the 60-day safe harbor established in D.03-05-034.[8] Giving an entity that needs only 60 days of supply a right to step into the shoes of the CCA under a 10-year contract, for example, is not only unnecessary but is unreasonable. If the contract provides products at prices below market, this will enable the POLR to profit by exercising the right and sell the output beyond 60 days at the prevailing market price. This result steps far beyond the bounds of simply enabling the POLR to have the supply needed to serve customers in the safe harbor period.

In addition, a POLR ROFR presents serious legal questions in the context of bankruptcy, where the provision would have its greatest value. A POLR ROFR provision likely would be unenforceable in a bankruptcy since it would undermine the court's jurisdiction in distributing the estate's assets or reorganizing its obligations. The Supremacy Clause of the Constitution mandates that federal laws, such as those concerning bankruptcy, "shall be the supreme Law of the Land; . . . [the] Laws of any State to the Contrary notwithstanding."[9] "Congress' intent to supersede state law altogether may be found from a "'scheme of federal regulation . . . so pervasive as to make reasonable the inference that Congress left no room for the States to supplement it,' because 'the Act of Congress may touch a field in which the federal interest is so

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8 D.03-05-034, Conclusion of Law 10.
9 U.S. Const., art. VI, cl. 2.

dominant that the federal system will be assumed to preclude enforcement of state laws on the same subject."[10]

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

> There can be no doubt that federal bankruptcy law is 'pervasive' and involves a federal interest 'so dominant' as to 'preclude enforcement of state laws on the same subject'--much like many other areas of congressional power listed in Article I, Section 8, of the Constitution, such as patents, copyrights, currency, national defense and immigration. The Bankruptcy Clause, which grants Congress the power to make bankruptcy laws, *U.S. Const. art. I, § 8, cl. 4*, stresses that such rules must be 'uniform.' Bankruptcy law occupies a full title of the United States Code. It provides a comprehensive system of rights, obligations and procedures, as well as a complex administrative machinery that includes a special system of federal courts and United States Trustees. [11]

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

> Notwithstanding a provision in an executory contract or unexpired lease, or in applicable law, an executory contract or unexpired lease of the debtor may not be terminated or modified, and any right or obligation under such contract or lease may not be terminated or modified at any time after the commencement of the case solely because of a provision in such contract or lease that is conditioned on …the commencement of a case under this title ….[12]

The reasoning underlying this rule goes to the very heart of bankruptcy's purpose. Complementary sections of the Bankruptcy Code empower a debtor in bankruptcy, or the

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

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

12 11 U.S.C. § 365(e)(1).

assigned trustee, to "assume," "assume and assign" or "reject" contracts. 11 U.S.C. § 365(a) and (c). The power to assume, and to assume and assign, valuable contracts is one of the principal benefits of a bankruptcy filing. As the Ninth Circuit court of Appeal explained:

> By invalidating such [*ipso facto*] clauses, § 365(e)(1) promotes the rehabilitation of the debtor by enabling the bankruptcy trustee to assume (and thus continue in force) beneficial contracts that otherwise would have terminated automatically or would have been terminated by the other contracting party. See H.R. Rep. No. 95-595, at 348-49, reprinted in 1978 U.S.C.C.A.N. 5963, 6304-05 (noting that enforcement of ipso facto clauses "frequently hampers rehabilitation efforts"). In short, the purpose of § 365(e)(1) is to protect the debtor from the enforcement of unfavorable insolvency-triggered clauses in executory contracts.[13]

A POLR ROFR thus faces strong legal headwinds. While courts have found in some cases that the Bankruptcy Code is not preempted by a particular state law, those rulings typically conclude that there is no conflict between the state law and the Bankruptcy Code, either because both are capable of being performed or because the *ipso facto* prohibition is not triggered.[14]

Not only does a POLR ROFR raise preemption concerns, it likely would also raise the price of contracting for CCAs and inhibit sales of excess resources by a CCA. First, it is unclear whether any generator or market participant would actually transact with the POLR ROFR as a

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

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

contractual condition. Second, even if they were willing, all such conditions come at a cost and, in this case, a cost only to the CCA or ESP; the IOU and its customers would be unaffected. The contract will be priced based upon the risk of not only the buyer but of the third-party entity as well. Third, there are existing contracts that do not contain these provisions with some of those being long-term contracts to meet RPS requirements. To implement a new requirement would potentially mean the re-negotiation of contracts whose terms and conditions may have been set years prior. Any such renegotiation will result in one party or the other seeking additional changes to a contract entered into in good faith drawing into question the value of long-term contracting in California's complicated energy space. Fourth, serious questions arise whether and under what terms and conditions the CCA could resell the output under the contract if it is burdened by a POLR ROFR.

b. Are there any other recommended changes to the established rules for all load-serving entities in preparation for any potentially large and unplanned customer migration, pursuant to Section 387 (h)1?

CalCCA does not have any comments on this question at this time.

2. To fulfill POLR service duties, can the POLR rely on purchasing energy on the CAISO market, or should the POLR be ordered to do some advance procurement/hedging?

The POLR should be required to purchase energy from the California Independent System Operator (CAISO) market. Because it is impossible to predict if, when, and to what extent customers may be returned, effective hedging would be very challenging, if even feasible. Only two things are certain: (1) the POLR will over-hedge or under-hedge and (2) hedging comes at a cost. The latter reality raises the additional question of who pays these costs. CalCCA submits that it would be unreasonable to ask customers of LSEs who did not return their customers – whether bundled IOU or other LSEs' customers – to bear these costs. To avoid unnecessary costs, CalCCA recommends that the POLR procure energy from the CAISO market without hedging.

E. Notice and Monitoring of LSE Financial Status

The CPUC has little direct insight as to CCA operations. While the CCAs do have public meetings and disclosures, there are no requirements to make the CPUC or the IOU informed of the financial or energy positions of the CCAs (apart from the RA filings). While CCAs have rate-making authority, the CPUC is ultimately responsible for making sure that the ratepayers are protected.

1. SB 520 requires that the CPUC establish rules for all load-serving entities in preparation of any potentially large and unplanned customer migration. Abrupt dissolution of a CCA is a challenge to ensuring continuity of service. What changes to current rules and requirements could address this risk in advance of POLR service being needed?

CalCCA represents public entities and supports transparency, including providing the Commission insight to the financial health of CCAs. CalCCA recommends enhanced implementation planning to ensure the Commission has predictable, standardized information on a timely basis before a new CCA launches. [15] CalCCA is working with members to make their already publicly available financial information and policies easier to locate and review. CalCCA proposes to consider limited financial reporting to the Commission in exchange for a waiver of the FSR under some circumstances. [16]

The nature, type, and depth of information necessary to make an informed decision about the financial health of an entity is a matter of debate and should be discussed further in this proceeding. The Commission should ensure a durable approach such that all entities are

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[15] *See supra*, at 14-15.
[16] *See supra*, at 17-18.

evaluated for risk similarly and appropriately, including the IOUs in the future if a non-IOU serves as POLR.

2. How much advance notice should the CPUC receive from an LSE about their financial status if it is causing them to fall short of meeting their procurement obligations?

CalCCA looks forward to proposals from the Commission regarding this question. The question should be considered in coordination with CalCCA's response to section V1, question B.1 above.

VII. CONCLUSION

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

Respectfully submitted,

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Evelyn Kahl
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CALIFORNIA COMMUNITY CHOICE ASSOCIATION

December 17, 2021

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 CCAS ON BUILDING DECARBONIZATION PHASE II STAFF PROPOSAL

I. INTRODUCTION

In accordance with the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission") and the November 16, 2021 Assigned Commissioner's Amended Scoping Memo and Ruling ("Ruling"), the Joint CCAs[1] hereby submit opening comments on the Phase III Building Decarbonization Staff Proposal submitted by Energy Division on November 16, 2021 ("Staff Proposal").

The Staff Proposal recommends elimination of gas line extension allowances, refunds, and discounts for all customer classes.[2] Energy Division staff highlight that these changes would signal to the building community the necessary transition away from fossil fuel to a healthy, clean all-electric future. Appendix B in the Staff Proposal poses nine questions. The Joint CCA's Opening Comments respond to questions 2-4 regarding the elimination of the gas line extension allowances, refunds, and discounts.

[1] The Joint CCAs are the following Community Choice Aggregation ("CCA") programs: East Bay Community Energy ("EBCE"), MCE, Sonoma Clean Power ("SCP"), and Peninsula Clean Energy ("PCE").
[2] Staff Proposal, p. 2

The Joint CCAs support the Staff Proposal. Elimination of subsidies encouraging expanding fossil fuel infrastructure is long overdue. The current tariffs charge all customers approximately $115m/year to subsidize a relative handful of customers expanding the natural gas system. To continuing this blunting of state and local electrification policies at ratepayer expense would be irrational.

CCA building electrification and decarbonization programs throughout California are making electrification of homes and businesses an economically attractive option. For example, EBCE, PCE, and SVCE are developing a multi-jurisdiction model reach code promoting all-electric construction. Prior to the multi-jurisdiction model reach code effort, EBCE and PCE supported thirty-two jurisdictions in development of some version of all-electric or electric preferred reach codes. PCE and EBCE both offer incentives to reduce the installed cost of heat-pump water heater (HPWH) technology, and both CCAs have programs in development to support the electrification of low to moderate income households. MCE's Low-Income Families and Tenants ("LIFT") pilot program (within the Energy Savings Assistance Program) installed heat pumps in low-income households and gathered information about bill impacts to inform future rate design in the context of electrification. These programs all accelerate the deployment of all-electric buildings and reduce the potential future impacts of degasification on rates.

The subsidies that the Staff Proposal addresses currently provide an unlevel playing field in favor of high-carbon-emitting technologies. It is time for their removal. The Joint CCAs encourage Commission adoption of the Staff Proposal, and eliminate gas line extension allowances, refunds, and allowances for all customer classes.

II. COMMENTS

At the conclusion of the Staff Proposal in Appendix B, Energy Division provided nine questions for Parties. The Joint CCAs are responding to Questions 2-4 under Appendix B:

> 2. *Should the Commission eliminate or modify gas line extension allowances provided in current gas rules for all or some of the customer classes (residential and non-residential)? If so, explain why.*
>
> 3. *Should the Commission eliminate or modify the 10-year refundable payment option for all or some of the customer classes (residential and nonresidential)? If so, explain why.*
>
> 4. *Should the Commission eliminate or modify the 50 percent discount payment option for all or some of the customer classes (residential and nonresidential)? If so, explain why.*

Each question included three identical sub-questions. The first two sub-questions applied only if a Party supported modification rather than elimination of the gas line extension subsidies. The third sub-question asked about the impacts on affordable housing and low-income customers.

The Joint CCAs support eliminating the gas line extension subsidies, not a modification. The Joint CCAs therefore respond here to the primary questions and to each sub-question C thereunder.

The elimination of gas line extension subsidies will result in rate relief for all customers, while advancing the phase-out of fossil fuel infrastructure. All-electric build is cost-competitive and a healthier alternative to natural gas.[3] The State should be, and elsewhere is, encouraging *decommissioning* of fossil fuel infrastructure. There is no reason to continue subsidizing *extension* of the natural gas system.

The Commission should accordingly eliminate gas line extension allowances, refunds, and discounts for all customer classes, residential and non-residential alike. While a customer can still apply to connect to a utility's gas system, the costs of subsidizing the connection should no longer be passed down to ratepayers. The Staff Proposal predicts that elimination of gas line extension allowances, refunds, and discounts would save ratepayers about $115 million in annual costs.[4] The Joint CCAs agree with the Staff Proposal that elimination of gas line extension subsidies will "help further relieve rate pressures." Affordability is a critical issue for the State to address,[5] and the proposed changes lower costs for all ratepayers.

Eliminating gas line extension allowances, refunds, and discounts removes the current artificial incentives for new, dual-fuel construction projects and so will promote all-electric builds. Cost effectiveness tests performed in support of REACH code development shows that all-electric new construction is the most cost-effective pathway to all-electric buildings; all-electric new construction is currently cost competitive with dual-fuel buildings. All-electric buildings also provide important health and safety benefits to the occupants; there are emerging studies showing the connection between combustion of natural gas in buildings on asthma and other respiratory impacts[6]. Ratepayers should not be burdened by subsidizing new, dual-fuel

[3]https://www.ethree.com/wp-content/uploads/2019/04/E3_Residential_Building_Electrification_in_California_April_2019.pdf
[4] Staff Proposal, p. 35.
[5] Staff Proposal, p. 41.
[6] https://rmi.org/uncovering-the-deadly-toll-of-air-pollution-from-buildings/

builds. New construction should be all-electric, moving the State closer to achieving SB 100's goals.[7]

The Joint CCAs appreciate the concerns raised by Energy Division about the impacts of the proposed policies, particularly as it relates to building new affordable housing. Given the need to address climate change and affordability expeditiously, the Commission should not delay the proposed tariff changes. The Joint CCAs support Energy Division studying potential impacts on affordable housing, while concurrently adopting the Staff Proposal eliminating allowances. Removing the gas line extension allowances, refunds, and discounts will lead to an annual costs reduction for ratepayers, while equitably incentivizing electrification in the building sector.

III. CONCLUSION

The Joint CCAs appreciate the opportunity to provide these comments on the Phase III

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[7] Staff Proposal, p. 35.

Building Decarbonization Staff Proposal. The Joint CCAs look forward to an ongoing dialogue with the Commission on these issues.

Dated: December 20, 2021

Respectfully submitted,

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DOCKETED	
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CALCCA ADVANCING LOCAL ENERGY CHOICE

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE STAFF PRE-RULEMAKING WORKSHOP ON UPDATES TO THE POWER SOURCE DISCLOSURE REGULATIONS WORKSHOP
December 7, 2021

Docket 21-OIR-01
Rulemaking to Amend Regulations Governing the Power Source Disclosure Program

I. INTRODUCTION

The California Community Choice Association (CalCCA)[1] submits these comments on the *Staff Pre-Rulemaking Workshop On Updates To The Power Source Disclosure Regulations Workshop* (Workshop), held on December 7, 2021.

II. COMMENTS

At the Workshop, Commission staff proposed several redlines to the Power Source Disclosure (PSD) regulations, including audit requirements for public agencies, Power Content Label (PCL) due dates and formatting, new community choice aggregator (CCA) greenhouse gas (GHG) reporting requirements, and unbundled Renewable Energy Credit (REC) reporting requirements.[2] These redlines increase the clarity of the PSD requirements and improve administrative efficiency, thus benefiting all stakeholders. Therefore, the Commission should adopt all of them, especially the proposal that new CCAs have 24 months after serving their first customer to report GHG emissions data.[3] This proposal appropriately

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[1] California Community Choice Association represents the interests of 23 community choice electricity providers in California: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

[2] California Energy Commission. *Proposed Updates to the PSD Program Regulations* at 8-12, located at https://efiling.energy.ca.gov/GetDocument.aspx?tn=240842&DocumentContentId=74676.

[3] *Id* at 10.

recognizes that newly formed CCAs need time to build up their portfolios and establish long-term contracting positions.

At the Workshop, Commission staff solicited input on handling Power Charge Indifference Adjustment (PCIA) resource allocations in the PSD program.[4] Three recommendations on how to implement this are below.

First, the Commission should continue its current calculation approach for the interim GHG-free allocations that load serving entities (LSE) have elected to take as part Phase 2 of the PCIA Order Instituting Rulemaking (PCIA OIR) at the California Public Utilities Commission (CPUC).[5] Currently, if an LSE receives a GHG-free allocation from the investor-owned utility (IOU), they can count the corresponding large hydro or nuclear resources as carbon-free in their PCL. This current approach is reasonable and there is no reason for the Commission to deviate from it in future versions of the PCL calculations.

Second, the Commission should attribute the Renewable Portfolio Standard (RPS) value of future IOU allocations of renewable energy under the Voluntary Allocation and Market Offer (RPS VAMO)[6] to the LSEs electing to receive the allocation. This is a logical extension of the current rules for counting the interim GHG-free allocations, which as described above allow an LSE to count a GHG-free allocation towards their PCL. There is no reason that RPS VAMO resources should not be also counted in the PCL.

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4 *Id* at 13.

5 These interim GHG-free allocations are already implemented via IOU advice letters (see PG&E 5705-E, located at https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_5705-E.pdf and SCE 4194-E, located at https://www.sce.com/sites/default/files/inline-files/GHGFEA_4194-E.pdf). For more context, see *Final Report Of Working Group 3 Co-Chairs: Southern California Edison Company (U-338E), California Community Choice Association, And Commercial Energy* , section V-C at 30: "GHG -Free Voluntary Allocation."

6 The RPS VAMO was adopted in CPUC Decision (D.) 21-05-030. See Ordering Paragraph 2 at 63.

Third, the Commission should treat different Portfolio Content Category (PCC)[7] resources in a VAMO allocation as follows: (i) PCC 1 resources should be treated as "Directly Delivered Renewables" in Schedule 1 in the PSD Annual Report template;[8] (ii) PCC 2 resources should be treated as "Firmed-and-Shaped Imports" in Schedule 1; (iii) PCC 3 resources should be treated as "Retired Unbundled RECs" in Schedule 2; and (iv) PCC 0 resources should be assigned as determined by the CPUC.[9]

To simplify PSD reporting, the Commission could create a separate VAMO allocation portfolio section in the template that CCAs and Energy Service Providers (ESPs) can use to report their energy sources. This avoids the need for each CCA/ESP to separately list its proportional share of each of the allocated resources. As both Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (SCE) have several hundred RPS-eligible contracts, this would create both a substantial reporting burden for the CCA/ESPs and an equally complex compliance verification process for Commission staff.

III. CONCLUSION

CalCCA appreciates Commission staff's efforts in Docket 21-OIR-01 and looks forward to further collaboration on this topic.

Date: December 21, 2021

(*Original signed by*)

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7 D.21-05-030 at 27 defers to the CEC on the treatment of these resources in the PCL: "It is reasonable and consistent with existing Commission decisions on RPS contracts to preserve the bundled nature of energy and associated RECs through sales contracts. PCL attributes are within the jurisdiction of the California Energy Commission."

8 This is the Microsoft Excel template that calculates PCL portfolio mix and GHG emissions, based on a set of contracts that the LSE enters.

9 For more information on different PCC types, see: https://www.cpuc.ca.gov/-/media/cpuc-website/industries-and-topics/documents/energy/rps/pcc-book2020.docx.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

INFORMAL COMMENTS OF SILICON VALLEY CLEAN ENERGY AUTHORITY, PENINSULA CLEAN ENERGY AUTHORITY, MARIN CLEAN ENERGY, SAN JOSE CLEAN ENERGY AUTHORITY, SONOMA CLEAN POWER AUTHORITY, AND CENTRAL COAST COMMUNITY ENERGY ON THE DRAFT ELECTRIFCIATION IMPACT STUDY PLAN AND POTENTIAL STAKEHOLDER VETTING PROCESS ON IEPR SENARIOS

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December 21, 2021

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

INFORMAL COMMENTS OF SILICON VALLEY CLEAN ENERGY AUTHORITY, PENINSULA CLEAN ENERGY AUTHORITY, MARIN CLEAN ENERGY, SAN JOSE CLEAN ENERGY AUTHORITY, SONOMA CLEAN POWER AUTHORITY, AND CENTRAL COAST COMMUNITY ENERGY ON THE DRAFT ELECTRIFCIATION IMPACT STUDY PLAN AND POTENTIAL STAKEHOLDER VETTING PROCESS ON IEPR SENARIOS

Pursuant to direction from Energy Division Staff, Silicon Valley Clean Energy Authority, Peninsula Clean Energy Authority, Marin Clean Energy, San Jose Clean Energy, Sonoma Clean Power Authority, and Central Coast Community Energy (collectively, the "Joint CCAs") respectfully submit these informal comments addressing the draft Electrification Impacts Study Plan ("Draft Plan") and potential stakeholder vetting process on Integrated Energy Policy Report ("IEPR") scenarios to use for 2023 Grid Needs Analysis ("GNA") and Distribution Deferral Opportunity Report ("DDOR"). The Joint CCAs appreciate the opportunity to provide our views on the Draft Plan discussed at workshop held on the December 7, 2021, and on potential avenues to review the investor-owned utilities ("IOUs") proposed scenarios for use in the 2023 GNA/DDOR Report.

I. Comments on the Draft Plan

At a high level, the Joint CCAs support the scope of the Draft Plan and the proposed scenarios the Electrification Impacts Study ("Study") will assess. The Joint CCAs believe that studying each of the three proposed time horizon scenarios is important to obtain a better understanding of the impacts California's collective state and local programs, standards and policies will have on energy demand and GHG emissions. The forecasts will also help illuminate what further efforts may be needed to "close the gap" so Californian can achieve its electrification goals – a necessary component of combating climate change.

The Joint CCAs support electrification as a key means of decarbonizing California's economy and have, therefore, adopted a suite of aggressive programs to support *and accelerate* beneficial electrification. To that end, the Joint CCAs have supported their jurisdictions implementation of building codes that require electrification beyond what state-level standards currently require. In this regard, the Joint CCAs believe the granular premise-level analysis to build a "bottom up" model as proposed in the Draft Plan is the correct approach, as doing so will allow for research into the impact of our collective efforts, and if the Study is structured correctly it will allow for comparison of electrification in jurisdictions that have not adopted aggressive reach codes.

Additionally, the Joint CCAs strongly support the proposal to assess mitigation strategies within the Study. To be frank, transmission and distribution ("T&D") costs are skyrocketing. These continuous cost increases directly and materially threaten electrification as a viable decarbonization strategy. Accordingly, a robust and thoughtful discussion of what additional standards, programs, and policies that utilize reasonable assumptions beyond those included in the Study, is essential to implementing reasonable cost containment strategies to ensure just and reasonable rates that support necessary decarbonization.

To ensure the final Study is as accurate and robust as possible, the Joint CCAs support full stakeholder access to the data, assumptions and methodologies utilized in developing the Study. Access to data and methodologies utilized to develop the Study will increase transparency around the Study which has several benefits. First, a transparent and accessible process allows stakeholders to understand the approaches to be utilized in the Study and provide meaningful feedback on whether other methodologies or approaches could provide more accuracy. Second, a transparent and accessible process allows stakeholders to file more informed and specific comments during the proceeding via participation in workshops and comments. Both benefits provide stakeholders an opportunity to assist the Commission in ensuring the Study is accurate and useful in future efforts.

Granting the Joint CCAs access to granular premise & circuit level data, assumptions and methodologies utilized in the Study will also allow the Joint CCAs to assist the Commission's consultants in understanding how existing policies and programs developed and deployed by the Joint CCAs are impacting load now and in the future during the time horizons proposed for the Study. The Joint CCAs welcome an opportunity to work with the Commission, its consultants, and stakeholders in the docket to leverage our expertise across a range of disciplines, as will be necessary to bring forward the best possible outcomes.

The Joint CCAs are sensitive to the need to maintain confidentiality of customer-specific data provided by the IOUs, but strongly believe that appropriate protocols, such as non-disclosure agreements, can be developed to address any confidentiality concerns. Nondisclosure agreements ("NDAs") have been developed in a number of Commission dockets to allow parties access to sensitive data on both customer load and utility infrastructure. They have also been utilized between CCAs and IOUs to facilitate data exchange so CCAs can discharge their duties to develop targeted customer programs that foster electrification and resiliency. Being able to rely on NDAs to enable sharing of data allows CCAs to make informed decisions about offerings for shared CCA-IOU customers. It also allows for information about these customers' participation and impacts to be shared with IOUs, creating a virtuous cycle. For example, recently, the ability to share sensitive customer information enabled Sonoma Clean Power and

PG&E to collaborate on a 100% renewable, off-grid solution. In this case, the avoided distribution costs from no longer having to maintain and service lines subject to repeated fire and PSPS risk produced rate reductions for all energy consumers. Most importantly, the Joint CCAs are load serving entities already subject to extensive confidentiality requirements to ensure customer data is handled in a manner that maintains customer confidentiality and privacy. If the Commission believes it necessary, the Joint CCAs would support differential levels of access to data in order to address any legitimate concerns.

II. Comments on the future vetting process for IOU's proposed IEPR scenarios

The Joint CCAs support stakeholders having an opportunity to comment on the IEPR scenarios in the future. The Joint CCAs take note of the idea presented in slide 27 of the slidedeck utilized by Energy Division Staff at the December 7th workshop noting stakeholder comments as a "TBD" for Quarter 2, 2022. The Joint CCAs support a round of comments during Quarter 2, 2022 as the minimum amount of stakeholder process for the Commission to utilized in seeking feedback from stakeholders regarding the future IOU requests. While the time to comment on the current request has past, we would note that the utilization of "Mid-Mid" for Solar PV, Energy Storage, Load Modifying Demand Response, and Load and the utilization of the "Mid-Low" for Energy Efficiency may not align these demand side management opportunities with the growing and accelerating adoption of all these strategies to control T&D costs. For this reason, the Joint CCAs welcome an opportunity to comment on the IOU's request via a round of comments – as the minimum amount of stakeholder process.

III. CONCLUSION

The Joint CCAs appreciate the opportunity to provide these informal comments in response to Staff's request.

DATED: December 21, 2021

Respectfully submitted,

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DOCKETED

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on the Draft 2021 IEPR

Additional submitted attachment is included below.

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE DRAFT 2021 INTEGRATED ENERGY POLICY REPORT (IEPR)

Docket 21-IEPR-01
General Scope, TN# 240868

I. INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

The California Community Choice Association (CalCCA)[1] submits these comments on the *Draft 2021 Integrated Energy Policy Report (IEPR), Volumes I, II, IV, and Appendix* (Report).[2] CalCCA appreciates the significant efforts of the California Energy Commission (Commission) in its analysis and preparation of the Report.

While many important issues are raised in the Report, the comments herein provide recommendations with respect to Volume II regarding actions needed to increase the reliability and resiliency of California's energy system.[3] As set forth more fully below, CalCCA provides the following recommendations to build on the proposals set forth in the Report:

- The Commission should ensure the appropriate use by state agencies of the annual near-term Summer Stack Analyses (SSA) and the longer-term California Reliability Outlook (CRO);
- Considerations of climate change and the social cost of carbon should be incorporated in Commission modeling; and

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1 California Community Choice Association represents the interests of 23 community choice electricity providers in California: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

2 As noted in the Notice of Availability of the Draft 2021 IEPR, Volume III related to the role of gas in California's energy system will be available for comment later and under separate notice. *Notice of Availability and Request for Comments on the Draft 2021 Integrated Energy Policy Report (IEPR), Docket No. 21-IEPR-01* (Dec. 7, 2021), at 2.

3 *Erne, David, Mark Kootstra, Tom Flynn, Chris McLean, Angela Tanghetti, and Stephanie Bailey.* 2021. *Draft 2021 Integrated Energy Policy Report, Volume II: Ensuring Reliability in a Changing Climate.* California Energy Commission. Publication Number: CEC-100-2021-001-V2.

- The Commission correctly recognizes its role in encouraging, but not mandating, the establishment by community choice aggregators (CCA) of dynamic rates for load management.

II. COMMENTS

A. The Commission's Summer Stack Analyses and California Reliability Outlook are Both Valid Tools for Assessing Reliability Needs, but Must be Used Appropriately

CalCCA supports the Commission's plan to annually perform *both* the SSA and a CRO to inform energy agency decision-making as instrumental to ensuring future system reliability. However, information gleaned from these analyses must be used appropriately. The Report distinguishes the purpose of these two tools proposed by the Commission to assess reliability conditions on an annual basis. First, the SSA will provide a near-term snapshot of a worst-case, extreme weather scenario on the California Independent System Operator (CAISO) system. This snapshot will enable preparation of contingency reserve needs (i.e., reduction of demand by industrial customers, use of backup generators, deployment of temporary mobile generators).[4] The CRO, on the other hand, will assess procurement needs in the mid-term (five-year period) through a loss-of-load-expectation (LOLE) analytical framework.[5] The Commission distinguishes the SSA from the CRO by stating that "the intention of a stack analysis is *not* to determine whether traditional procurement is needed."[6] The necessity of additional resource procurement (i.e., renewables and storage) to address system reliability needs would be informed only by the CRO.[7]

CalCCA agrees with the Commission's intended use of information gleaned from the SSA and CRO, and recommends the following additional principles. First, emergency

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4 Report, Vol. II, at 48-49.
5 *Id.* at 53-54.
6 *Id.* at 49 (emphasis added).
7 *Id.* at 53.

procurement orders for new-build resources in the short-term should be avoided. Any new-build system need beyond contingency resources (as identified in the SSA) should only be identified in the CRO, and LSEs should be given adequate time to procure the needed resources. Rushing procurement timelines imposes costs on ratepayers that should be avoided with adequate planning. Second, as CalCCA has advocated in the Integrated Resource Planning (IRP) proceeding at the California Public Utilities Commission (CPUC), the Commission should not recommend changing the Planning Reserve Margin (PRM) without a robust record that includes LOLE analysis.[8] Third, the Commission should make the data inputs and outputs of each SSA and CRO available for stakeholder review and input.

With the above caveats, CalCCA supports the Commission's proposed roles for its SSA and CRO. Through these annual analyses, the Commission can balance the timely, agile identification of the need for contingency responses to near-term grid issues under extreme conditions via the SSA. The Commission can also ensure a systematic, data-driven approach to medium-term procurement and planning of new build resources via the CRO. The ultimate goal

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[8] See *California Community Choice Association's Reply Comments on Administrative Law Judge's Ruling Seeking Comments on Proposed Preferred System Plan,* Rulemaking (R.) 20-05-003 (Oct. 11, 2021), at 9 (quoting *California Community Choice Association's Comments on Administrative Law Judge's Ruling Seeking Feedback on Mid-Term Reliability Analysis and Proposed Procurement Requirements,* CPUC R.20-05-003 (Mar. 26, 2021), Appendix A, at A-2) ("A PRM should be calculated using a robust stakeholder process, employing the following high-level steps. First, decide on a "target" of grid reliability that can be achieved at a reasonable cost. Historically, this has been one loss-of-load event every ten years (often referred to as "0.1 LOLE," which is a count of the expected number of loss-of-load events in a given year). However, the CPUC may want to revisit this number (and the underlying weather and load data) to account for climate change or affordability impacts, as well as the increased renewable and battery penetration in the grid relative to when the 0.1 target was first established. Second, calculate the amount of generating resources that are required to achieve this target using a production cost model. Third, divide that amount by the load forecast, incorporating an operating reserve margin adder. The result will be the PRM that should be used"), located at https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M410/K467/410467139.PDF.

of this balancing will be to ensure system reliability while avoiding imposing unnecessary long-term costs on customers through emergency procurement orders.[9]

B. The CEC Should Consider Climate Change and the Social Cost of Carbon in any New Reliability Analysis, Including its Next California Reliability Outlook

CalCCA appreciates the Commission's acknowledgement of the need to incorporate climate change into grid planning, and recommends that considerations of climate change and the social cost of carbon be incorporated into its next CRO.[10] As it has previously commented before the Commission and the CPUC, CalCCA agrees that climate-driven changes in the electric system should be studied including the effects on hydroelectric, wind, solar, and thermal generation, as well as on load.[11] CalCCA has analyzed both historical daily maximum temperature data (including 30 years of historical data)[12] and projected future temperature data (next 15 years) for summer days.[13] The chart below shows the probability density functions of

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9 *See Reply Comments of California Community Choice Association on the Proposed Decision and Alternate Proposed Decision Requiring Procurement to Address Mid-Term Reliability (2023-2026),* CPUC R.20-05-003 (June 15, 2021), at 1 (advocating that the cost and time necessary to conduct a robust LOLE study prior to ordering procurement beyond the mid-need scenario is worth ensuring any reliability benefits given the potential significant costs), located at https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M388/K397/388397136.PDF.

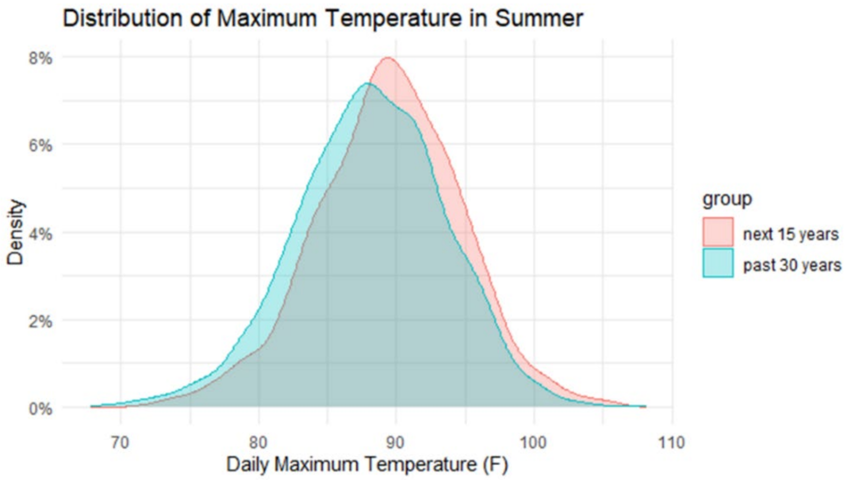
10 Report Vol. II, at 74 ("[t]he CEC, CPUC and California ISO should develop a common approach to incorporating climate change into system planning, including a set of climate scenarios to be considered").

11 *See Comments of the California Community Choice Association to the California Energy Commission on the November 1 Joint Agency Workshop on Planning for SB 100 Analysis of Non-Energy Benefits, Social Costs & Reliability,* CEC Docket No. 19-SB-100 (Nov. 9, 2021), at 2-3, located at https://efiling.energy.ca.gov/GetDocument.aspx?tn=240533&DocumentContentId=73853; *see also California Community Choice Association's Comments on Administrative Law Judge's Ruling Seeking Comments on Proposed Preferred System Plan,* CPUC R.20-05-003 (Sept. 27, 2021), at 7-9 (recommending that any future CPUC SERVM analysis take into account climate change, include potential future prolonged hydro years and the social costs of carbon emissions), located at https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M410/K467/410467139.PDF.

12 Historical temperature data is from PRISM Climate Data Daily Summaries, located at https://prism.oregonstate.edu/historical/.

13 Future data is from Rasmussen, D. J., Holloway, T., & Nemet, G. F. (2011). Opportunities and challenges in assessing climate change impacts on wind energy—a critical comparison of wind speed projections in California. *Environmental Research Letters*, 6(2), 024008. Located at https://iopscience.iop.org/article/10.1088/1748-9326/6/2/024008.

the historical data (in blue) and the future data (in red). The data clearly demonstrates a future substantial increase in the frequency of high-temperature summer days.



CalCCA looks forward to engaging with Commission staff on further analysis of these data, and incorporation of the results into system modeling and the IEPR more generally.

CalCCA also proposes that any future Commission modeling consider the social cost of carbon. As CalCCA has advocated before the CPUC, "cost-optimized energy portfolios must include all costs borne by customers, not just portfolio costs, including the costs of wildfires, drought, heat waves and heat-related outages induced by emissions from the electricity sector."[14] As all of these are climate-related, and the Commission should take them into account when modeling for grid planning purposes.

C. The Commission's Recommendations Regarding Expansion of Dynamic Rate Plans to Support Load Management Goals Correctly Recognize the CEC's Role to Encourage, Rather Than Mandate, Such Rates for CCAs

The Report provides recommendations concerning the Commission's and CPUC's efforts regarding the state's demand response program to take advantage of flexible-demand appliances

[14] *See California Community Choice Association's Comments on Administrative Law Judge's Ruling Seeking Comments on Proposed Preferred System Plan,* CPUC R.20-05-003 (Sept. 27, 2021), at 7, footnote 14, located at https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M410/K467/410467139.PDF.

and the market-informed demand automation server (MIDAS).[15] Among the recommendations are that the Commission and CPUC "should work to expand dynamic rate plans and encourage the rollout of automated devices."[16] The recommendation regarding expansion of dynamic rates correctly states that "the CPUC and [Commission] will need to *coordinate with* . . . [CCAs] to *encourage* these entities to implement similar rate plans and automate access to them".[17] Given the lack of jurisdiction of the Commission and the CPUC over CCA ratemaking, the Commission correctly recognizes that the adoption of any rate structure cannot be mandated for CCAs, but rather can only be encouraged.[18] CCAs appreciate the Commission's efforts to encourage the development of rates that can result in decreased electricity use in peak hours. However, the adoption of such rates by a CCA would be dependent on the cost-effectiveness of such a rate, and how such a rate fits within the CCA's unique local needs.[19]

III. CONCLUSION

CalCCA appreciates Commission's staff's efforts in Docket Number 21-IEPR-01 and looks forward to further collaboration on this topic.

Date: December 21, 2021

(*Original signed by*)

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15 Report at 75.

16 *Id.*

17 *Id.* (emphasis added).

18 *See Comments of the California Community Choice Association to the California Energy Commission on the Draft Staff Report,* CEC Docket No. 10-OIR-01, Rulemaking to Consider Updates to the Load Management Regulations (June 4, 2021), at 3-6 (requesting revisions to draft Load Management Regulations to ensure that the regulations do not improperly subject CCAs to prescriptive ratemaking mandates that would infringe upon each CCA's exclusive ratemaking authority), located at https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=19-OIR-01.

19 *See id.* at 5-6 (encouraging the Commission to adopt flexible rate recommendations to allow each CCA Board to determine whether such a rate, including the resources and technology necessary to implement the rate, would be cost-effective for its customers or class of customers).

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

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S RESPONSE TO JOINT MOTION OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E), PACIFIC GAS AND ELECTRIC COMPANY (U 39-E) AND SAN DIEGO GAS & ELECTRIC COMPANY (U 902-E) TO AMEND SCOPING MEMORANDUM TO ACCOMMODATE VOLUNTARY ALLOCATION STRUCTURE

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On behalf of
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December 23, 2021

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S RESPONSE TO JOINT MOTION OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E), PACIFIC GAS AND ELECTRIC COMPANY (U 39-E) AND SAN DIEGO GAS & ELECTRIC COMPANY (U 902-E) TO AMEND SCOPING MEMORANDUM TO ACCOMMODATE VOLUNTARY ALLOCATION STRUCTURE

In accordance with Rule 11.1(e) of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission), the California Community Choice Association[1] (CalCCA) respectfully submits this response to the joint motion of Southern California Edison Company, Pacific Gas and Electric Company, and San Diego Gas & Electric Company (together, the Joint IOUs), filed December 8, 2021 (Motion). This response is timely filed pursuant to Rule 11.1(e).

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[1] California Community Choice Association represents the interests of 23 community choice electricity providers in California: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

I. THE JOINT IOUS' MOTION REQUESTING EXPANSION OF THE SCOPE TO CONSIDER AND FIND THAT VOLUNTARY ALLOCATIONS UNDER VAMO ARE NOT "RESALES" REQUIRING RECLASSIFICATION OF RECS ALLOCATED TO NON-IOU LSES SHOULD BE GRANTED

The Motion requests the Commission (1) expand the scope of Rulemaking (R.) 18-07-003 to address the Product Content Category (PCC) classification of Renewable Energy Credits (RECs) upon allocation under the Voluntary Allocation and Market Offer (VAMO) process adopted in Decision (D.) 21-05-030,[2] (2) provide guidance on the PCC classification of certain allocated RECs, and (3) clarify the timing and approval process for Voluntary Allocation pro forma contracts. CalCCA supports the Joint IOUs' request to amend the Scoping Memorandum in R.18-07-003 on an expedited basis to address the classification of RECs allocated to non-investor-owned utility (IOU) load-serving entity (LSEs) during the VAMO process. CalCCA agrees with the Joint IOUs that voluntary allocations under VAMO are not "re-sales" that would require reclassification of RECs allocated to non-IOU LSEs. The VAMO allocation structure is an inherently different construct than the "re-sales" contemplated by D.11-12-052, and there is no Commission decision requiring RECs allocated under VAMO to be so considered. Departed load customers already pay for the above market costs of the resources in question, which were originally procured on their behalf. As stated in the Motion, "[a]llocation of the RECs under the Voluntary Allocation process simply allows the value of PCC 0 RECs to follow the departed load customers who are already obligated to pay for them."[3]

[2] D.21-05-030 was adopted May 24, 2021 in the Power Charge Indifference Adjustment docket, R.17-06-026.

[3] Motion at 5.

II. THE JOINT IOUS' PROPOSALS REGARDING THE TIMING AND APPROVAL OF PRO FORMA CONTRACTS FOR THE VAMO PROCESS ARE BEING ADDRESSED IN COMMENTS ON THE PROPOSED DECISION

Subsequent to the filing of the Motion, Administrative Law Judges Lakhanpal and Sisto issued their Proposed Decision in this proceeding.[4] The Proposed Decision discusses issues related to the timing and approval of the pro forma contracts to be used in the VAMO allocations and market offers.[5] As such, CalCCA reserves its comments regarding these topics for its comments on the Proposed Decision.

III. CONCLUSION

CalCCA appreciates the opportunity to submit this response and requests adoption of the recommendations proposed herein.

Respectfully submitted,

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December 23, 2021

4 Proposed *Decision on 2021 Renewables Portfolio Standard Procurement Plans,* R.18-07-003 Dec. 10, 2021 (refd;.l/Proposed Decision).

5 *Id.*, Conclusion of Law 3 at 78.

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

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION ON 2021 RENEWABLES PORTFOLIO STANDARD PROCUREMENT PLANS

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SUMMARY OF RECOMMENDATIONS

- ✓ The requirement that CCAs and ESPs update their Final 2021 RPS Plans to describe whether they plan to participate in the voluntary allocation and/or market offer should be removed, given that parties will not have had an opportunity to review the proposed terms and conditions of the voluntary allocation and market offer contracts;
- ✓ The IOUs should be required, either separately or together, to hold a workshop for stakeholders to review the IOU's proposed voluntary allocation pro forma contracts, and a separate workshop for stakeholders to review the proposed market offer pro forma contracts, prior to the IOUs submitting the Advice Letters seeking those contracts' approval; and
- ✓ All of the IOUs, including SCE and SDG&E, in addition to PG&E, should be required to file Tier 2 Advice Letters proposing pro forma contracts for VAMO allocations and sales.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION ON 2021 RENEWABLES PORTFOLIO STANDARD PROCUREMENT PLANS

The California Community Choice Association (CalCCA)[1] submits these comments pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure on the proposed *Decision on 2021 Renewables Portfolio Standard Procurement Plans* (Proposed Decision or PD), mailed on December 10, 2021.

I. INTRODUCTION

The PD addresses certain issues concerning the voluntary allocation and market offer (VAMO) process established by Decision (D.) 21-05-030, issued in the Power Charge Indifference Adjustment (PCIA) proceeding.[2] The PD requires the 2021 Final Renewable Portfolio Standard (RPS) Plans of community choice aggregators (CCAs) and electric service

1 California Community Choice Association represents the interests of 23 community choice electricity providers in California: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

2 D.21-05-030, *Phase 2 Decision on Power Charge Indifference Adjustment Cap and Portfolio Optimization,* R.17-06-026 (May 20, 2021); *Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment,* Rulemaking (R.) 17-06-026 (June 29, 2017).

providers (ESPs) "to describe whether they plan to participate in the VAMO process and purchase renewable energy credits (RECs) in the IOU's Market Offer."[3] The PD also adopts the timeline for review of the pro forma voluntary allocation contract (Voluntary Allocation Contract) and pro forma market offer contract (Market Offer Contract) put forward by Pacific Gas and Electric Company (PG&E) in its Motion to Update its RPS Plan, which Southern California Edison Company (SCE) and San Diego Gas & Electric (SDG&E) both seconded.[4] However, the PD fails to require PG&E, SCE or SDG&E (collectively, the IOUs) to hold one or more workshops to seek comment on the proposed terms and conditions of the Voluntary Allocation and Market Offer Contracts.

As set forth more fully below, CalCCA recommends the following modifications to the PD to ensure a methodical and commercially reasonable VAMO process:

- ✓ The requirement that CCAs and Electric Service Providers (ESPs) update their Final 2021 RPS Plans to describe whether they plan to participate in the voluntary allocation and/or market offer should be removed, given that parties will not have had an opportunity to review the proposed terms and conditions of the voluntary allocation and market offer contracts;
- ✓ The IOUs should be required, either separately or together, to hold a workshop for stakeholders to review the IOUs' proposed voluntary allocation pro forma contracts, and a separate workshop for stakeholders to review the proposed market offer pro forma contracts, prior to the IOUs submitting the Advice Letters (ALs) seeking those contracts' approval; and
- ✓ All of the IOUs, including SCE and SDG&E, in addition to PG&E, should be required to file Tier 2 Advice Letters proposing pro forma contracts for VAMO allocations and sales.

[3] PD at 13.
[4] *Id.* at 14.

II. BACKGROUND

The review and approval of the procedure and form of contracts to be used in VAMO allocations and sales have been the subject of numerous motions by interested stakeholders in this proceeding. PG&E filed a motion on September 13, 2021, to update its Draft 2021 Renewable Energy Procurement Plan (PG&E Motion to Update).[5] PG&E requested the Commission authorize it to submit the Voluntary Allocation Contract via a Tier 2 AL "within 10 days of the submission of its Final 2021 RPS Procurement Plan."[6] In addition, PG&E requested authority to submit the pro forma contract to be used in the subsequent market offer of RPS resources remaining in its portfolio (Market Offer Contract) for approval within 45 days of submission of its Final RPS Procurement Plan.[7] PG&E noted that its Final 2021 RPS Procurement Plan "is likely to be submitted in early 2022."[8] SCE and SDG&E each subsequently filed motions to update their respective draft 2021 RPS Procurement Plans requesting the timeline and approval process put forward by PG&E in its Motion to Update.[9]

In response to these motions, CalCCA requested the Commission require the IOUs to hold workshops for stakeholders to review and comment on the proposed terms of the Voluntary

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5 *Motion of Pacific Gas and Electric Company (U 39 E) to Update Its Draft 2021 Renewable Energy Procurement Plan*, R.18-07-003 (Sept. 13, 2021) (PG&E Motion to Update). PG&E filed its motion to update pursuant to the March 30, 2021 *Assigned Commissioner and Assigned Administrative Law Judge's Ruling Identifying Issues and Schedule of Review for 2021 Renewables Portfolio Standard Procurement Plans*, filed in this RPS proceeding, as updated by Administrative Law Judge Ruling, dated July 22, 2021, revising the procedural schedule for the 2021 Renewables Portfolio Standard Procurement Plans. *See E-Mail Ruling Granting Joint Investor Owned Utilities Request for Extension to File Motions to Update Draft 2021 Renewable Procurement Plans,* R.18-07-003 (July 22, 2021).

6 PG&E Motion to Update at 2.

7 *Id*. at 3.

8 *Id.* at 2.

9 *Motion of Southern California Edison Company (U 338-E) to Update Its 2021 Draft Renewables Portfolio Standard Procurement Plan*, R.18-07-003 (Sept. 13, 2021); *Response of Southern California Edison Company (U 338-E) to Motion to Update of Pacific Gas and Electric Company*, R.18-07-003 (Sept. 28, 2021); *Response of San Diego Gas & Electric Company (U 902 E) to the Motions of Pacific Gas & Electric Company and Southern California Edison Company*, R.18-07-003 (Sept. 28, 2021).

Allocation and Market Offer Contracts they would be asked to sign.[10] CalCCA also requested more time for the review and approval of the Market Offer Contract.[11] PG&E responded by suggesting a shorter schedule and process of review.[12] In addition, PG&E suggested no workshops were necessary, and requested that not more than one workshop be required.[13]

The IOUs jointly filed a motion to amend the Scoping Memorandum in this proceeding on December 8, 2021.[14] That motion requested the Commission review and approve the Voluntary Allocation Contracts through a Tier 2 AL submitted within 10 days of the IOUs' submission of their Final 2021 RPS Procurement Plans.[15] The IOUs also requested that allocation contracts that do not deviate from the approved pro forma contract be authorized to commence on January 1, 2023 without further Commission review.[16]

III. FACTUAL, LEGAL, AND TECHNICAL ERRORS AND CLARIFICATIONS

A. CCAs Should Not Be Required to Commit to Voluntary Allocations or Market Offers Prior to Reviewing the Terms and Conditions of the Transactions

As CalCCA has emphasized, LSEs must determine whether the terms and conditions of the voluntary allocation offered to them align with their individual programmatic goals as well as

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10 *California Community Choice Association's Response to Motion of Pacific Gas and Electric Company (U 39 E) to Update Its Draft 2021 Renewable Energy Procurement Plan*, R.18-07-003 (Sept. 28, 2021) (CalCCA Response to PG&E Motion to Update) at 2; *California Community Choice Association's Motion in Response to San Diego Gas & Electric Company's (U 902 E) Update to Its 2021 Draft Renewables Portfolio Standard Procurement Plan*, R.18-07-003 (Sept. 28, 2021) at 3-4; *California Community Choice Association's Response to Motion of Southern California Edison Company (U 338 E) to Update Its 2021 Draft Renewables Portfolio Standard Procurement Plan*, R.18-07-003 (Sept. 28, 2021) at 4.

11 CalCCA Response to PG&E Motion to Update at 3-4.

12 *Pacific Gas and Electric Company's (U 39 E) Reply to Response on Motion to Update Draft 2021 Renewables Portfolio Standard Procurement Plan*, R.18-07-003 (Oct. 8, 2021) (PG&E Reply) at 3.

13 *Id.* at 5.

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

15 *Id.* at 12.

16 *Id*.

the requirements of D.21-05-030 prior to making the decision to accept or decline the allocation offered to them.[17] Under no other circumstances should an LSE be required to make a commitment to "purchase" without first having the opportunity to review all relevant contracts in their entirety. PG&E agrees, asserting that "LSEs should understand the terms and conditions of Voluntary Allocations prior to making such a commitment."[18] The same reasoning requires that the CCAs have an opportunity to review the terms of the contracts to be used in the Market Offer. As set forth more fully below, the PD should be revised to remove the requirement that CCAs indicate their participation in the VAMO process prior to the CCAs having an opportunity to review the terms of the voluntary allocation and market offer transactions.

In addition, the IOUs should be required to hold workshops to solicit stakeholders' input prior to submitting the ALs for approval of both the Voluntary Allocation Contracts and the Market Offer Contracts. CalCCA requests the PD be revised to include these requirements as set out in Attachment A.

1. The Commission Should Not Require CCAs and ESPs to Update Their 2021 Draft RPS Plans Indicating Whether They Plan to Participate in the Voluntary Allocation and/or Market Offer Prior to Reviewing the Terms and Conditions of the Transactions

The PD notes that "[m]ost of the CCAs and ESPs state [in their draft 2021 RPS Plans] that they are still reviewing their portfolios to decide whether and to what extent they would participate in the PCIA VAMO process."[19] Thus, CCAs and ESPs are required by the PD to update their Final 2021 RPS Plans "to describe whether they plan to participate in the VAMO process and purchase RECs in the IOUs' Market Offer."[20] The PD finds appropriate that the

17 CalCCA Response to PG&E Motion to Update at 3.
18 PG&E Reply at 3.
19 PD at 13.
20 *Id.*

IOUs have modeled the assumption that CCAs and ESPs will fully take their voluntary allocations, and cites the difficulty for IOUs determining their Renewable Net Short given the uncertainty surrounding CCA VAMO participation.[21] However, the PD fails to recognize that without yet knowing any terms or conditions related to the voluntary allocations or market offers, a party cannot be expected to commit to whether or under what terms it will participate. The requirement in the PD that the Final 2021 Plans be updated to describe whether a party plans to participate in the voluntary allocation and/or purchase RECs through the market offer should therefore be removed.

2. The IOUs Should Be Required to Hold Workshops to Solicit Stakeholders' Input Prior to Submitting the ALs for Approval of the Voluntary Allocation Contracts and Market Offer Contracts

The PD grants the IOUs' request to submit to the Commission via Tier 2 Advice Letter the Voluntary Allocation Contracts within 10 days, and the Market Offer Contracts within 45 days of submitting the Final 2021 RPS Plans.[22] However, the PD fails to order any workshops prior to the submittal of each pro forma contract to allow for LSE review and input. The terms and conditions of these contracts bear significantly on an LSE's decision whether to accept or decline the Voluntary Allocation and/or to participate in the Market Offer. LSEs must be given an opportunity to review and provide input on the proposed terms and conditions of these pro forma contracts.

Even PG&E recognizes the educational value of workshops on the pro forma contracts in its Reply on the Motion to Update, although it argues that "no more than one workshop and the General Order 96-B Protest process [is] adequate to educate LSEs and to address any comments

21 *Id.*
22 *Id.* at 14.

or concerns with PG&E's pro forma contracts.'[23] CalCCA appreciates PG&E's openness to early review of the pro forma contracts, and to a workshop for stakeholders on contract terms and conditions, but disagrees that only one workshop is necessary for both contracts. CalCCA requests the PD be modified to require the IOUs, together or separately, to hold workshops for LSEs to review and comment on the terms and conditions of both the Voluntary Allocation Contract and the Market Offer Contract. These workshop(s) must be held prior to the IOUs' submitting each pro forma contract for approval through the AL process.

B. Ordering Paragraph 6 of the PD Should Be Corrected to Require SCE and SDG&E, in Addition to PG&E, to File Tier 2 Advice Letters Proposing VAMO Pro Forma Contracts

Finally, Ordering Paragraph 6 of the PD should be corrected to require SCE and SDG&E, along with PG&E, to file Tier 2 Als proposing the Voluntary Allocation Contracts within 10 days of submission of their Final 2021 RPS Plans, and Market Offer Contracts within 45 days of their Final 2021 RPS Plans. While the text of the Decision, as well as Conclusion of Law 3, requires all three IOUs to submit the Tier 2 advice letter, Ordering Paragraph 6 requires only PG&E to file the Tier 2 advice letter.[24] This technical error in the PD should be corrected as set forth in Appendix A.

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[23] PG&E Reply at 5.

[24] PD at 14 ("[w]e grant the IOUs' request to submit a Tier 2 Advice Letter proposing Voluntary Allocation REC pro forma contracts within 10 days of submitting their Final 2021 RPS Plans and Market Offer pro forma contracts within 45 days of submission of Final 2021 RPS Plans"); PD, Conclusion of Law 3 at 78 ("Each IOU must submit a Tier 2 advice letter proposing Voluntary Allocation REC pro forma contracts within 10 days of submitting its Final 2021 RPS Plan, and Market Offer pro forma contracts within 45 days of submission of Final 2021 RPS Plans"); PD, Ordering Paragraph 6 at 82("Pacific Gas and Electric Company shall file Tier 2 advice letters proposing Voluntary Allocation of [REC] pro forma contracts within 10 days of submission of its Final 2021 [RPS Plan] and Market Offer pro forma contracts within 45 days of submission of Final 2021 RPS Plan, respectively").

IV. CONCLUSION

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

Respectfully submitted,

Evelyn Kahl

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

December 30, 2021

ATTACHMENT A

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

FINDINGS OF FACT

9. An advice letter filing <u>preceded by a workshop</u> will enable retail sellers to review the pro forma contracts before executing agreements for their respective voluntary allocations and provide a standardized process for all VAMO transactions.

CONCLUSIONS OF LAW

3. Each IOU must submit a Tier 2 advice letter proposing Voluntary Allocation REC pro forma contracts within 10 days of submitting its Final 2021 RPS Plan. Prior to submitting such advice letter, each IOU<u> must hold a workshop to enable retail sellers to review and comment on the proposed Voluntary Allocation REC pro forma contracts</u>. Each IOU must submit a Tier 2 advice letter proposing Market Offer pro forma contracts within 45 days of submission of Final 2021 RPS Plans. Prior to submitting such advice letter, each IOU <u>must hold a workshop to enable retail sellers to review and comment on the proposed Market Offer pro forma contracts.</u>

ORDERING PARAGRAPHS

6. Pacific Gas and Electric Company<u>, Southern California Edison Company, and San Diego Gas & Electric Company</u> shall <u>each </u>file Tier 2 advice letters proposing <u>its</u> Voluntary Allocation of renewable energy credit pro forma contracts within 10 days of submission of its Final 2021 Renewables Portfolio Standard Procurement Plan (RPS Plan) and Market Offer pro forma contracts within 45 days of submission of <u>its</u> Final 2021 RPS Plan, respectively. <u>Each IOU shall hold a workshop, either jointly or separately, prior to submitting the advice letter proposing its Voluntary Allocation of renewable energy credit pro forma contracts, and another workshop prior to submitting the advice letter proposing the Market Offer pro forma contract, to enable retail sellers to review and comment on each of the pro forma contracts.</u>

28. The final 2021 Renewables Portfolio Standards Procurement Plans of Apple Valley Choice Energy, City of Baldwin Park, City of Palmdale, City of Pomona, City of Santa Barbara, Clean Energy Alliance, Clean Power Alliance, Desert Community Energy, Lancaster Choice

Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, Sonoma Clean Power Authority, Central Coast Community Energy, CleanPowerSF, East Bay Community Energy, King City Community Power, Valley Clean Energy Alliance, 3 Phases Renewables, Calpine Power America, Commercial Energy, Pilot Power Group, Shell Energy North America, The Regents of the University of California, Calpine Energy Solutions, Constellation NewEnergy, Direct Energy Business, EDF Industrial Power Services, also identified in Table 1 – Portfolio Optimization, Voluntary Allocation Market Offer and Mid-Term Reliability, in Section 4 of this decision, shall each provide an expanded planning scenario and/or analysis to forecast Decision 21-06-035's (Mid-Term Reliability Decision) impact on portfolio optimization~~ and an update on whether they plan to participate in voluntary allocation and purchase Renewable Energy Credits in the market offer pursuant to the Power Charge Indifference Adjustment Decision 21-05-030~~.

JANUARY FILINGS

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

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

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January 4, 2022

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SUMMARY OF RECOMMENDATIONS

- More information should be provided for parties to understand the underlying causes of the central procurement entities' (CPEs') failure to meet local Resource Adequacy (RA) requirements for 2023;
- The implementation steps for self-shown resources should not create additional disincentives to self-show local resources;
- The California Public Utilities Commission (Commission) should adopt Pacific Gas and Electric Company's (PG&E's) proposal to remove certain selection criteria and data submittal requirements;
- The Commission should not remove the requirement that utilities bid in at their levelized fixed costs;
- The Commission should ensure load-serving entities (LSEs) are aware of their system and flexible Cost Allocation Mechanism (CAM) allocations by the time the system and flexible requirements are established in June;
    - The Commission should allow the CPE to solicit local resources outside the all-source solicitation process so long as the procurement is complete and allocated by the time system and flexible RA requirements are finalized in June;
    - The Commission should not adopt PG&E's proposed timeline; and,
- CPE confidentiality provisions should be consistent with Decision (D.) 06-06-066.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

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

The California Community Choice Association[1] (CalCCA) submits these comments in response to the *Assigned Commissioner's Scoping Memo and Ruling* (Ruling), issued on December 2, 2021, requesting comments on Phase 1 proposals and workshop.

I. INTRODUCTION

CalCCA appreciates the opportunity to comment on parties' proposals submitted on December 13, 2021 and December 23, 2021, and parties' presentations at the December 14, 2021 workshop on the CPE framework. Publicly available information provided in this process thus far is insufficient to develop a problem statement for the failure of the CPE to meet its 2023 local RA requirements. This shortfall has left other LSEs with a high level of uncertainty about the amount CAM -allocated resources they can expect to receive, significantly complicating their

[1] California Community Choice Association represents the interests of 23 community choice electricity providers in California: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

2023 system and flexible RA procurement. In these comments, CalCCA expands on the information needed to fully evaluate the failure of CPE procurement for 2023 and responds to several parties' proposals, including those on implementing the self-showing process, removing the requirement for utilities to bid in resources at their levelized fixed costs, and allowing the CPE to solicit local resources outside the all-source solicitation process. In summary, CalCCA provides the following recommendations:

- More information should be provided for parties to understand the underlying causes of the CPEs' failure to meet local RA requirements for 2023;
- The implementation steps for self-shown resources should not create additional disincentives to self-show local resources;
- The Commission should adopt PG&E's proposal to remove certain selection criteria and data submittal requirements;
- The Commission should not remove the remove requirement that utilities bid in at their levelized fixed costs;
- The Commission should ensure LSEs are aware of their system and flexible CAM allocations by the time the system and flexible requirements are established in June;
    - The Commission should allow the CPE to solicit local resources outside the all-source solicitation process so long as the procurement is complete and allocated by the time system and flexible RA requirements are finalized in June;
    - The Commission should not adopt PG&E's proposed timeline; and,
- CPE confidentiality provisions should be consistent with D.06-06-066.

II. MORE INFORMATION SHOULD BE PROVIDED FOR PARTIES TO UNDERSTAND THE UNDERLYING CAUSES OF THE CPES' FAILURE TO MEET LOCAL RA REQUIREMENTS FOR 2023

The significant shortfall of CPE procurement for 2023 clearly demonstrates a failure of the CPE framework. This is not to say each CPE did not take reasonable actions to procure to meet its full local RA requirement but rather that the CPE framework itself has failed given it does not provide the right incentives to ensure that the CPEs' procurement obligations can be met. In order to identify solutions to this failure, additional information is needed to inform how the incentives and disincentives of the current framework inhibit the CPE from meeting its procurement targets. CalCCA's proposal included a list of information that is needed to determine the source of the CPEs' procurement deficiencies 2023.[2] Without this information, it is unclear whether proposed solutions will resolve the challenges faced by the CPE procuring local RA and other market participants offering or self-showing local RA.

In its workshop presentation[3] and Response to the Motion for Extension of Time of the Joint Movants[4], PG&E indicated that its CPE did not receive enough offers through self-showings or bids to meet its 2023 local RA obligations. Its response also included a summary of total procured and self-shown resources obtained by the CPE for 2023 and 2024, as well as total non-self-shown and self-shown resources offered to the CPE for 2023 and 2024.[5] This additional information is useful in understanding the current local RA landscape in PG&E's territory. However, it does not fully explain the shortfall of over 6,000 megawatts (MW), or roughly half the total requirement, in some months. The information provided by PG&E indicates the CPE did not accept all offers bid in or self-shown. However, it is not clear how many offers or self-showings were either withdrawn by the entity offering the resource or rejected by the CPE and the reasons for the withdrawal or rejection. Further, it is not clear the amount of capacity in the local

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[2] *California Community Choice Association's Phase 1 Proposals in Response to the Assigned Commissioner's Scoping Memo and Ruling,* Dec. 13, 2021 (CalCCA Proposals), at 4 and 12-14.

[3] PG&E Presentation at Workshop on Proposals to Modify the Central Procurement Entity (CPE) Structure, Dec. 14, 2021, at 17.

[4] *Response of Pacific Gas and Electric Company (U 39 E) to the Motion for Extension of Time of the Joint Movants*, Dec. 21, 2021 (PG&E Response).

[5] PG&E Response, Attachment 1.

area that was not offered at all and the type of entities that control that capacity (*e.g.,* generator owner, LSE, marketer). The information proposed by CalCCA in its Phase 1 Proposals is needed to understand:

- What offers were not acceptable to the CPE to evaluate whether such rejection was appropriate;
- What offers were withdrawn and what incentive created the need for the withdrawal; and
- What alternatives were available to resources that were not offered, including doing nothing with the resource, and what incentives caused this to occur noting that such incentives may be different depending on the party controlling the offer from the resource.

PG&E's response to the motion indicates any non-market participant can obtain access to confidential information upon execution of a non-disclosure agreement.[6] However, market participants are the parties best suited and most inclined to solve the problems with the CPE framework. For this reason, the additional information proposed by CalCCA can and should be provided in an aggregated manner to provide parties with enough information to fully understand the reasons for the shortfall while still protecting confidentiality.

Typically, parties will choose not to enter into a contract for a large variety of reasons (*e.g.,* price too high, term length too long, unacceptable other terms and conditions). PG&E's response to the joint parties' motion states, "In addition to the lack of offers received, PG&E also recognizes that there was offered capacity that remained unprocured due to the CPE and some counterparties not being able to agree on terms during the procurement process."[7] This is an important consideration, as the conflict in terms not only prevented offered MWs from being

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[6] PG&E Response at 8-9.

[7] PG&E Response at 10.

accepted, but may have contributed to resources not being offered at all. Without assessing the information CalCCA has suggested, making changes to the CPE procurement is guessing at the cause with no reasonable assurance that the changes to the solicitation process will lead to an outcome that procures the required amount of local RA.

III. THE IMPLEMENTATION STEPS FOR SELF-SHOWN RESOURCES SHOULD NOT CREATE ADDITIONAL DISINCENTIVES TO SELF-SHOW LOCAL RESOURCES

The California Independent System Operator (CAISO), PG&E, and Southern California Edison Company (SCE) offer proposals aimed at improving the self-showing process and ensuring self-shown resources are shown to the CAISO and Commission in RA plans. The CAISO proposes modify D.20-06-002 to allow the Commission to assign local capacity obligations to LSEs that have agreed to self-show resources to the CPE to allow the CAISO to first assign any local Capacity Procurement Mechanism (CPM) costs directly to the LSE that fails to show its self-shown resources to the CAISO.[8] PG&E proposes a process in which LSEs first voluntarily commit their self-procured local resources to the CPE. Then, the CPE provides its RA plan to the Commission including all self-showings and procured resources. The CPE then submits its showings to the CAISO while LSEs also submit their self-shown resources to the CAISO with the CPE as the benefitting entity. If an LSE does not submit their self-shown resources, that LSE's CAM credits would be revised, and any costs associated with CAISO backstop procurement would be directly allocated to the non-performing self-showing LSE.[9]

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[8] *Phase 1 Proposals of the California Independent System Operator Corporation*, Dec. 23, 2021.

[9] *Initial Phase 1 Proposals of Pacific Gas and Electric Company (U 39 E) Regarding Central Procurement Entity Structure and Process*, Dec. 13, 2021 (PG&E Proposals), at 3-7.

CalCCA does not support the CAISO's or PG&E's proposals, as either one will further disincentivize LSEs from self-showing. If a self-shown resource goes on outage after an LSE elects to self-show it in the year-ahead RA showing process, the LSE could face backstop costs for events outside its control. While this was the case under an LSE based local RA mechanism, the showing LSE directly benefited from the showing as each MW of the shown resource met their own RA requirement rather than the requirement of all LSEs. It was also known ahead of time that if the resource did not show up in an individual month, the LSE would be required to provide and alternative resource or pay the CAISO backstop costs since the obligation was on the individual LSE from the start.

Under the CAISO's or PG&E's proposals, if a self-showing LSE wanted to mitigate the risk of backstop costs being paid by the LSE in the event a self-shown resource becomes unavailable, it would need to procure additional local area resources that it holds for this purpose, assuming the CPE contract allows the LSE to provide a replacement resource when on outage. If the CPE does not allow such a replacement, then the LSE self-showing may not want to take the risk that the outage of the resource will have the LSE pay backstop costs when the original showing mitigated CPE cost risk for all LSEs serving load in the local area. Simply put, the incentive to self-show and the potential consequences for self-showing would not align.

In the case that the CPE allowed an LSE to provide a replacement resource, the LSE would now need to procure additional local area resources potentially at a premium. Even if the replacement resource is not charging a premium, the LSE would need to procure the local resource and not show it as local, instead holding it as a potential replacement resource in the event another self-shown resource is on outage. This will then create additional scarcity of local area resources that may further the difficulty for the CPE in procuring sufficient resources within the local area to meet the local need. Therefore, CAISO's and PG&E's proposals would likely reduce the amount of self-shown resources offered to the CPE. Given this, the Commission should not adopt either proposal.

SCE proposes a process in which LSEs elect to self-show their resources to the CPE with an attestation and backstop costs due to not submitting self-shown resources on RA plans due to planned outages would be charged to the CPE and paid by all customers in the CPE's service territory. It appears SCE proposes any backstop costs not due to planned outages submitted between the annual and monthly RA showings without replacement would be charged directly to the LSE that did not show its self-shown resources in its RA plan.[10] SCE should clarify if outages within this timeframe is the intended proposal, given the CAISO also accepts planned outages after the monthly showings until seven days prior to the outage if substitute capacity is provided. While SCE's proposal creates less disincentives to self-show than PG&E's proposal, at the current rate of the local capacity requirement (LCR) reduction compensation mechanism (RCM) of at most $1.78/kW-month, any backstop risk from self-showing could disincentivize entities from self-showing.

The Commission must consider a market participant's alternatives in making a rule such as that proposed by SCE. An LSE has three options; 1) self-show and potentially receive LCR RCM if applicable; 2) offer the entire resource for sale to the CPE; or 3) not self-show or offer to sell to the CPE. In the case of the third option, while the LSE would be allocated its share of CPE costs which would not be reduced by the self-shown resource, the LSE would also not take on

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10 *Phase 1 Proposals of Southern California Edison Company (U 338-E)*, Dec. 13, 2021 (SCE Proposals), at 3-5.

any risk of CPM backstop costs individually from the CAISO. Further, LSE's may not be eligible for LCR RCM either because there is no premium or because the resources does not qualify for the premium. In this case, the LSE is balancing a load ratio share of reduced CPE costs against a potential for backstop costs on a MW-for-MW self-shown basis at the CAISO CPM rate which is likely to be $6.31/kW-Month but could be higher or lower.[11] It is evident that for a small LSE, the potential savings in CPE costs by self-showing are minor compared to the potential for CPM costs to be allocated to them directly. Even in cases where the LCR RCM is available at a rate higher than $0, the incentive is still minimal as the highest LCR RCM value is $1.78/kW-month. With the CPM likely at $6.31/kW-month, that means that even in the highest paying LCR RCM area, a probability of outage greater than 28 percent yields an expected value lower than not self-showing due to the expected CPM costs that would be incurred.

Effectively, the SCE proposal makes the self-provision of a local resource carry a liquidated damages provision. While the LSE may be able to successfully replace the resource for its system showing, it may not be able to do so for the local attribute. Given that LSEs procuring local resources at this point are only doing so for system needs, it is unlikely that the LSE would have similar provisions in its contract with the supplier since the local risk would not have been a subject of the negotiation since the LSE did not have a local obligation. Without understanding the incentives or disincentives LSEs have for self-showing, it is not clear if SCE's proposal will reasonably resolve the existing issues with the self-showing process while not disincentivizing LSEs from self-showing.

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11 The CAISO CPM has a soft-offer cap of $6.31/kW-Month but offerors may bid lower and are eligible for compensation in excess of this cap if they demonstrate to the Federal Energy Regulatory Commission that their costs are higher than the soft-offer cap.

Finally, even if this issue can be solved for the current instant, the Commission must keep in mind the incentives for the development of new local area resources. If any new resource procurement in a local area comes with the same risks discussed above, there will be significant disincentive for LSEs to develop new resources in local areas. This is because the LSE will have significant risk of realizing the local value of the resource through the LCR RCM given the risk of backstop costs that currently outstrips the LCR RCM value by a factor of three or more.

IV. THE COMMISSION SHOULD ADOPT PG&E'S PROPOSAL TO REMOVE CERTAIN SELECTION CRITERIA AND DATA SUBMITTAL REQUIREMENTS

CalCCA supports PG&E's proposal to revise the selection criteria in Ordering Paragraph (OP) 14 of D.20-06-002, and the data submittal requirements in OP 15 of D.20-06-002.[12] PG&E's proposal would remove certain selection criteria and data submittal requirements that may create unnecessary barriers to offering resources to the CPE. Certain operational characteristics requested by the CPE in the last solicitation are not accessible to LSEs. Further, these requirements may have contributed to LSEs and CPEs being unable to reach agreement on contract terms and conditions. For these reasons, the Commission should adopt PG&E's proposal.

V. THE COMMISSION SHOULD NOT REMOVE THE REQUIREMENT THAT UTILITIES BID IN AT THEIR LEVELIZED FIXED COSTS

PG&E[13] and SCE[14] propose to remove the requirement that investor-owned utilities (IOUs) must bid their resources at their levelized fixed costs. The Commission should not adopt this proposal. Allowing the IOUs to bid their resources at a value other than their levelized fixed costs would mean allowing the IOUs to charge CAM customers a different cost than the cost charged to PCIA customers, effectively transferring costs from one set of customers to another.

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12 *New Phase 1 Proposals of Pacific Gas and Electric Company (U 39 E) Regarding Central Procurement Entity Structure and Process*, Dec. 23, 2021 (New PG&E Proposals), at 1-5.

13 PG&E Proposals at 8-9.

14 SCE Proposals at 6-8.

In addition, the Commission originally approved the resource costs as reasonable for the IOUs customers to incur to serve their needs and hedge their future price risk. The PCIA then has retail access load pay for the above market costs of this hedge. Removing the levelized fixed cost requirement would provide the IOUs with the ability to bid their resources at prices that are unrestricted.[15] For these reasons, the Commission should not remove the requirement that the IOUs to bid their resources at their levelized fixed costs. If the Commission does decide to remove this restriction, it should not allow the IOUs to bid above the levelized fixed cost of the resource effectively capping the bids to ensure that the IOU stated intent of procuring local RA by the CPE at a lower cost is realized.

PG&E indicates the levelized fixed cost requirement is incompatible with the products being procured by the CPE and how the bundled procurement arm's portfolio is comprised, presenting a barrier to participating in the CPE process.[16] This implies that the IOU should be allowed to bid below the levelized fixed cost in order to reflect the only the RA value to compete with others that are offering on the RA value to the CPE. However, the Commission has long recognized that the IOUs may need to evaluate bids that are on a different basis included length of term and products offered. All source solicitations do exactly this. While PG&E notes the issue surrounding the allocation of RPS through CAM[17], this is not a sufficient reason to allow a tier 2 advice letter to formulate a new process for the costs that the IOU is allowed to bid in a CPE solicitation. If the Commission believes that a change from the levelized fixed cost is

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15 While SCE at page 8 sites to potentially lower costs for customers from allowing bids that are not based upon the levelized fixed cost, SCE's proposal does not cap the IOU bids at levelized fixed costs meaning in times of scarcity, the IOU could bid above the levelized fixed cost and there is a possibility that the CPE would procure that resource causing customers to pay through CAM a level higher than what they otherwise would have paid in PCIA eliminating the hedge that was believed to have been procured by the IOU within the original contract.

16 PG&E Proposals at 8.

17 *Id.* at 8.

warranted, such a decision must be delivered through this OIR so that it is reasonably contemplated and so that proposals to address the concerns can be offered by more than just the IOU bundled procurement arm as suggested by PG&E.

VI. THE COMMISSION SHOULD ENSURE LSES ARE AWARE OF THEIR SYSTEM AND FLEXIBLE CAM ALLOCATIONS BY THE TIME THE SYSTEM AND FLEXIBLE REQUIREMENTS ARE ESTABLISHED IN JUNE

A. The Commission Should Allow the CPE to Solicit Local Resources Outside the All-Source Solicitation Process So Long as the Procurement is Complete and Allocated by the Time System and Flexible RA Requirements are Finalized in June

SCE proposes to allow the CPE to procure local resources outside the annual CPE solicitation, including "allowing the CPE to conduct procurement through other means, such as the broker markets or bilateral transactions, and on different timelines to meet local sub-area needs or other local needs that arise beyond the typical timeline for local capacity requirements."[18] CalCCA supports allowing the CPE to procure local resources outside the annual CPE solicitation. However, this procurement must be completed and RA quantities for system and flexible must be allocated to LSEs by the time the system and flexible RA requirements are finalized in June, so that LSEs know their system and flexible CAM allocations in time for them to complete their own procurement. CalCCA's proposal outlined a modified timeline for 2023 that would reach this objective.[19] Any procurement outside of an all-source solicitation should follow this proposed timeline and be communicated in supplemental compliance reports prior to the finalization of system and flexible RA requirements in June 2022.

[18] SCE proposals at 8.
[19] CalCCA Proposals at 10-12.

B. The Commission Should Not Adopt PG&E's Proposed Timeline

PG&E recognizes LSEs need sufficient time to incorporate CPE procurement into their planning of their own system and flexible procurement.[20] However, its proposed timeline in which LSEs would receive their CAM credits for system and flexible RA procured by the CPE in mid-August does not allow LSEs enough time to effectively plan to meet their year-ahead obligations. CalCCA proposed that to fill the gap in local RA procurement for 2023, the timeline should allow the CPE to complete its all-source solicitations for 2023 by June so that allocations can be completed by the time LSEs receive their system and flexible requirements. Even this timeline encroaches on LSEs' ability to plan their system and flexible procurement, as many LSEs will begin procurement of 2023 system and flexible RA soon, if they have not already. For this reason, CalCCA proposed this timeline only to fill the significant gap in local procurement for 2023; in future years, local RA procurement should be completed by October, two years prior to the operational year.

Therefore, instead of adopting PG&E's proposal, the Commission should allow the CPE to conduct procurement outside the all-source solicitation process to speed up the procurement process for 2023 and adopt the timeline proposed by CalCCA that would communicate system and flexible credits to LSEs by the time their RA requirements are finalized in June. If the CPE cannot effectively conduct another all-source and complete the solicitation by June to procure for 2023, the CPE should instead solicit additional procurement outside the all-source solicitation process as discussed in section A above.

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[20] New PG&E Proposals at 5.

VII. CPE CONFIDENTIALITY PROVISIONS SHOULD BE CONSISTENT WITH D.06-06-066

In its proposal, PG&E provides a table summarizing its proposal for confidential treatment of CPE information which deviates from D.06-06-066 in some areas. Under the category of "Contract Terms and Conditions," PG&E proposes contracts and power purchase agreements be confidential for a period of the later of three years from delivery start or one year after execution.[21] This should be clarified, consistent with D.06-06-066, to specify that contract summaries are public, including counterparty, resource type, location, capacity, expected deliveries, delivery point, length of contract and online date.[22]

Under the category "Forecast," PG&E proposes "Forecasted RA Requirements" and "Allocations (MW)" be confidential for three years. PG&E's justification for keeping this information confidential is, "Disclosure of the capacity that is forecasted to be sold in each local area could potentially have an adverse effect on the market, put the CPE at a competitive disadvantage with regard to other market participants, and impact participants' future bidding behavior for capacity that has not yet been procured."[23] This justification is not clear given the description of the item is related to forecasted requirements and allocations rather than capacity sales. Forecasted requirements are published by the Commission three years forward, and the CPE is allocated all the local RA requirements. Additionally, aggregate CAM allocations are published and should continue to be published so LSEs are aware of their own procurement obligations. Therefore, it is not clear what the forecasted requirements and allocations are that PG&E is proposing to keep confidential. The Commission should ensure CPE confidentiality provisions are consistent with those outlined in D.06-06-066.

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21 PG&E Proposals at A-1.
22 D.06-06-066 at Appendix 1, p 15.
23 PG&E Proposals at A-3.

VIII. CONCLUSION

For all the foregoing reasons, CalCCA respectfully requests consideration of these comments and looks forward to continuing the dialogue with the Commission and stakeholders around the CPE framework.

Respectfully submitted,

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

January 4, 2022

California ISO

Submit comment on Issue paper and straw proposal

Initiative: Interconnection process enhancements 2021

1. Provide a summary of your organization's comments on the Interconnection Process Enhancements (IPE) 2021 issue paper and straw proposal:

California Community Choice Association (CalCCA) supports an alternative cost allocation treatment for network upgrades to local systems (below 200 kV) where the associated generation benefits more than, or other than, the customers within the service area of the Participating Transmission Owner (PTO) owning the facilities, as described in Section 9 below.

2. Provide your organization's comments on the ISO's proposal to remove the downsizing window and simplifying downsizing request requirements, as described in section 3.1, as modified in the stakeholder discussion that if a network upgrade only impacts that project, then the ISO would not need to wait for the reassessment to make a final decision on the downsizing:

3. Provide your organization's comments on the ISO's proposal for revising the Transmission Plan Deliverability (TPD) Allocation process, as described in section 3.3:

4. Provide your organization's comments on the ISO's proposal for addressing the question of how can the interconnection process and procurement activity align with transmission system capabilities and renewable generation portfolios developed for planning purposes, as described in section 3.4:

5. Provide your organization's comments on the ISO's proposal for determining if a solicitation model be considered for some key locations and constraints not addressed in portfolio development, as described in section 3.6:

6. Provide your organization's comments on the ISO's proposal for determining if an accelerated process for "Ready" projects be considered, as described in section 3.7:

7. Provide your organization's comments on the ISO's proposal for determining if higher fees, deposits, or other criteria be required for submitting an IR, as described in section 4.1:

8. Provide your organization's comments on the ISO's proposal for determining if site exclusivity be required to progress into the Phase II study process, as described in section 4.2:

9. Provide your organization's comments on the ISO's proposal for determining if the ISO should re-consider an alternative cost allocation treatment for network upgrades to local (below 200 KV) systems where the associated generation benefits more than, or other than, the customers within the service area of the Participating TO owning the facilities, as described in section 5.1:

CalCCA supports a cost allocation methodology that allocates costs to all those who receive benefits. As such, CalCCA supports re-considering an alternative cost allocation for network upgrades to local systems when the benefits extend beyond just those within the PTO service area in this initiative. To mitigate the risk that interconnection-related local network upgrades may create disproportionate impacts on a single set of ratepayers, the California Independent System Operator (CAISO) proposes to cap the percentage of interconnection-related network upgrade costs within each PTO's local transmission revenue requirement (LTRR). For any network upgrades that exceed the PTOs aggregate cap, interconnection customers would finance any network upgrades without reimbursement or move their generator interconnection to the high voltage system.[1] The CAISO's proposal to cap the percentage of interconnection-related network upgrade costs in each PTO's LTRR improves the current structure with respect to protecting local ratepayers from the cost impact of network upgrades that benefit all customers. However, the CAISO should describe how the proposal will treat upgrades that benefit all customers if they fall under the proposed cap. If the purpose of the network upgrades is for generation projects to be deliverable anywhere on the grid, then all customers benefit and should share the costs.

10. Provide your organization's comments on the ISO's proposal for determining the policy for ISO as an Affected System - how is the base case determined and how are the required upgrades paid for, as described in section 5.2:

11. Provide your organization's comments on the ISO's proposal for the expanded errors and omissions process to provide criteria and options when changes to network upgrade requirements occur after Financial Security (IFS) postings have been made, as described in section 5.3:

12. Provide your organization's comments on the ISO's proposal for clarifying the definition of Reliability Network Upgrade (RNU), as described in section 5.4:

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[1] Interconnection Process Enhancements Issue Paper and Straw Proposal at 32-33.

13. Provide your organization's comments on the ISO's proposal for transferring Participating Transmission Owner (TO) Wholesale Distribution Access Tariff (WDAT) Projects into ISO Queue, as described in section 5.5:

14. Provide your organization's comments on the ISO's proposal for changing sites and POIs during IR validation, as described in section 5.6:

15. Provide your organization's comments on the ISO's various questions for addressing whether the ISO have the ability to terminate the GIA earlier than the seven year period, if a project cannot prove that it is actually moving forward to permitting and construction, as described in section 5.7:

16. Provide your organization's comments on the ISO's proposal for should parked projects be allowed to submit any type of MMAs while parked, as described in section 5.8, and if yes, what criteria should be required:

17. Provide your organization's comments on the added scope item from SCE to add due dates for curing deficiencies in Appendix B, to avoid delays in starting Phase II studies, as described in section 6.1:

18. Provide your organization's comments on the added scope item from SCE to make it explicit that when ICs agree to share a gen tie-line, PTO interconnection facilities, and any related IRNUs at a substation across clusters, the shared IRNUs are not subject to GIDAP Section 14.2.2, as described in section 6.1:

19. Provide your organization's comments on the added scope item from Gridwell on a proposal to include an issue focused on improved transmission grid data transparency, and specifically what data your organization would like to obtain publically, as described in section 6.2:

20. Provide your organization's comments on the added scope item from LSA/SEIA to resolve delays caused by PTOs via modifications to commercial viability criteria, as described in section 6.3:

21. Provide your organization's comments on the added scope item from LSA/SEIA to address network upgrade re-stacking and how your organization would suggest the Participating TOs would prioritize the various upgrades versus project CODs, as described in section 6.3:

22. Provide your organization's comments on the added scope item from LSA/SEIA to address expanding deliverability transfer opportunities, as described in section 6.3:

23. Provide your organization's comments on the added scope item from CalWEA to address re-examining the ISP electrical independence test in section 6.4 and provide specific proposals for revisions to the ISP electrical independence test criteria that provides a methodology that addresses the condition where a current cluster project is impacted or a potential impact cannot be ruled out:

24. Provide your organization's comments on the added scope item from REV Renewables to address examining the issue of when a developer issues a notice to proceed to the PTO, requesting the PTO/ISO should start planning for all upgrades that are required for a project to attain FCDS, including the upgrades that get triggered by a group of projects, as described in section 6.4:

25. Provide your organization's comments on the added scope item from SDG&E recommending there be a requirement that any IR that proposes to utilize a third party owned gen-tie must provide documentation as part of their IR that demonstrates that the gen-tie owner has agreed to the project using its gen-tie, as described in section 6.4:

26. Provide your organization's comments on the added scope item from SDG&E recommending that after the IR validation, the ISO should be consistent in using RIMS for all documents, details, etc. related to projects, as described in section 6.4:

27. Additional comments on the IPE 2021 issue paper and straw proposal and December 13, 2021 stakeholder workshop discussion:

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

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

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January 4, 2022

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SUMMARY OF RECOMMENDATIONS

- More information should be provided for parties to understand the underlying causes of the central procurement entities' (CPEs') failure to meet local Resource Adequacy (RA) requirements for 2023;
- The implementation steps for self-shown resources should not create additional disincentives to self-show local resources;
- The California Public Utilities Commission (Commission) should adopt Pacific Gas and Electric Company's (PG&E's) proposal to remove certain selection criteria and data submittal requirements;
- The Commission should not remove the requirement that utilities bid in at their levelized fixed costs;
- The Commission should ensure load-serving entities (LSEs) are aware of their system and flexible Cost Allocation Mechanism (CAM) allocations by the time the system and flexible requirements are established in June;
    - The Commission should allow the CPE to solicit local resources outside the all-source solicitation process so long as the procurement is complete and allocated by the time system and flexible RA requirements are finalized in June;
    - The Commission should not adopt PG&E's proposed timeline; and,
- CPE confidentiality provisions should be consistent with Decision (D.) 06-06-066.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

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

The California Community Choice Association[1] (CalCCA) submits these comments in response to the *Assigned Commissioner's Scoping Memo and Ruling* (Ruling), issued on December 2, 2021, requesting comments on Phase 1 proposals and workshop.

I. INTRODUCTION

CalCCA appreciates the opportunity to comment on parties' proposals submitted on December 13, 2021 and December 23, 2021, and parties' presentations at the December 14, 2021 workshop on the CPE framework. Publicly available information provided in this process thus far is insufficient to develop a problem statement for the failure of the CPE to meet its 2023 local RA requirements. This shortfall has left other LSEs with a high level of uncertainty about the amount CAM -allocated resources they can expect to receive, significantly complicating their

[1] California Community Choice Association represents the interests of 23 community choice electricity providers in California: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

2023 system and flexible RA procurement. In these comments, CalCCA expands on the information needed to fully evaluate the failure of CPE procurement for 2023 and responds to several parties' proposals, including those on implementing the self-showing process, removing the requirement for utilities to bid in resources at their levelized fixed costs, and allowing the CPE to solicit local resources outside the all-source solicitation process. In summary, CalCCA provides the following recommendations:

- More information should be provided for parties to understand the underlying causes of the CPEs' failure to meet local RA requirements for 2023;
- The implementation steps for self-shown resources should not create additional disincentives to self-show local resources;
- The Commission should adopt PG&E's proposal to remove certain selection criteria and data submittal requirements;
- The Commission should not remove the remove requirement that utilities bid in at their levelized fixed costs;
- The Commission should ensure LSEs are aware of their system and flexible CAM allocations by the time the system and flexible requirements are established in June;
    - The Commission should allow the CPE to solicit local resources outside the all-source solicitation process so long as the procurement is complete and allocated by the time system and flexible RA requirements are finalized in June;
    - The Commission should not adopt PG&E's proposed timeline; and,
- CPE confidentiality provisions should be consistent with D.06-06-066.

II. MORE INFORMATION SHOULD BE PROVIDED FOR PARTIES TO UNDERSTAND THE UNDERLYING CAUSES OF THE CPES' FAILURE TO MEET LOCAL RA REQUIREMENTS FOR 2023

The significant shortfall of CPE procurement for 2023 clearly demonstrates a failure of the CPE framework. This is not to say each CPE did not take reasonable actions to procure to meet its full local RA requirement but rather that the CPE framework itself has failed given it does not provide the right incentives to ensure that the CPEs' procurement obligations can be met. In order to identify solutions to this failure, additional information is needed to inform how the incentives and disincentives of the current framework inhibit the CPE from meeting its procurement targets. CalCCA's proposal included a list of information that is needed to determine the source of the CPEs' procurement deficiencies 2023.[2] Without this information, it is unclear whether proposed solutions will resolve the challenges faced by the CPE procuring local RA and other market participants offering or self-showing local RA.

In its workshop presentation[3] and Response to the Motion for Extension of Time of the Joint Movants[4], PG&E indicated that its CPE did not receive enough offers through self-showings or bids to meet its 2023 local RA obligations. Its response also included a summary of total procured and self-shown resources obtained by the CPE for 2023 and 2024, as well as total non-self-shown and self-shown resources offered to the CPE for 2023 and 2024.[5] This additional information is useful in understanding the current local RA landscape in PG&E's territory. However, it does not fully explain the shortfall of over 6,000 megawatts (MW), or roughly half the total requirement, in some months. The information provided by PG&E indicates the CPE did not accept all offers bid in or self-shown. However, it is not clear how many offers or self-showings were either withdrawn by the entity offering the resource or rejected by the CPE and the reasons for the withdrawal or rejection. Further, it is not clear the amount of capacity in the local

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2 *California Community Choice Association's Phase 1 Proposals in Response to the Assigned Commissioner's Scoping Memo and Ruling,* Dec. 13, 2021 (CalCCA Proposals), at 4 and 12-14.
3 PG&E Presentation at Workshop on Proposals to Modify the Central Procurement Entity (CPE) Structure, Dec. 14, 2021, at 17.
4 *Response of Pacific Gas and Electric Company (U 39 E) to the Motion for Extension of Time of the Joint Movants*, Dec. 21, 2021 (PG&E Response).
5 PG&E Response, Attachment 1.

area that was not offered at all and the type of entities that control that capacity (*e.g.,* generator owner, LSE, marketer). The information proposed by CalCCA in its Phase 1 Proposals is needed to understand:

- What offers were not acceptable to the CPE to evaluate whether such rejection was appropriate;
- What offers were withdrawn and what incentive created the need for the withdrawal; and
- What alternatives were available to resources that were not offered, including doing nothing with the resource, and what incentives caused this to occur noting that such incentives may be different depending on the party controlling the offer from the resource.

PG&E's response to the motion indicates any non-market participant can obtain access to confidential information upon execution of a non-disclosure agreement.[6] However, market participants are the parties best suited and most inclined to solve the problems with the CPE framework. For this reason, the additional information proposed by CalCCA can and should be provided in an aggregated manner to provide parties with enough information to fully understand the reasons for the shortfall while still protecting confidentiality.

Typically, parties will choose not to enter into a contract for a large variety of reasons (*e.g.,* price too high, term length too long, unacceptable other terms and conditions). PG&E's response to the joint parties' motion states, "In addition to the lack of offers received, PG&E also recognizes that there was offered capacity that remained unprocured due to the CPE and some counterparties not being able to agree on terms during the procurement process."[7] This is an important consideration, as the conflict in terms not only prevented offered MWs from being

6 PG&E Response at 8-9.
7 PG&E Response at 10.

accepted, but may have contributed to resources not being offered at all. Without assessing the information CalCCA has suggested, making changes to the CPE procurement is guessing at the cause with no reasonable assurance that the changes to the solicitation process will lead to an outcome that procures the required amount of local RA.

III. THE IMPLEMENTATION STEPS FOR SELF-SHOWN RESOURCES SHOULD NOT CREATE ADDITIONAL DISINCENTIVES TO SELF-SHOW LOCAL RESOURCES

The California Independent System Operator (CAISO), PG&E, and Southern California Edison Company (SCE) offer proposals aimed at improving the self-showing process and ensuring self-shown resources are shown to the CAISO and Commission in RA plans. The CAISO proposes modify D.20-06-002 to allow the Commission to assign local capacity obligations to LSEs that have agreed to self-show resources to the CPE to allow the CAISO to first assign any local Capacity Procurement Mechanism (CPM) costs directly to the LSE that fails to show its self-shown resources to the CAISO.[8] PG&E proposes a process in which LSEs first voluntarily commit their self-procured local resources to the CPE. Then, the CPE provides its RA plan to the Commission including all self-showings and procured resources. The CPE then submits its showings to the CAISO while LSEs also submit their self-shown resources to the CAISO with the CPE as the benefitting entity. If an LSE does not submit their self-shown resources, that LSE's CAM credits would be revised, and any costs associated with CAISO backstop procurement would be directly allocated to the non-performing self-showing LSE.[9]

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[8] *Phase 1 Proposals of the California Independent System Operator Corporation*, Dec. 23, 2021.
[9] *Initial Phase 1 Proposals of Pacific Gas and Electric Company (U 39 E) Regarding Central Procurement Entity Structure and Process*, Dec. 13, 2021 (PG&E Proposals), at 3-7.

CalCCA does not support the CAISO's or PG&E's proposals, as either one will further disincentivize LSEs from self-showing. If a self-shown resource goes on outage after an LSE elects to self-show it in the year-ahead RA showing process, the LSE could face backstop costs for events outside its control. While this was the case under an LSE based local RA mechanism, the showing LSE directly benefited from the showing as each MW of the shown resource met their own RA requirement rather than the requirement of all LSEs. It was also known ahead of time that if the resource did not show up in an individual month, the LSE would be required to provide and alternative resource or pay the CAISO backstop costs since the obligation was on the individual LSE from the start.

Under the CAISO's or PG&E's proposals, if a self-showing LSE wanted to mitigate the risk of backstop costs being paid by the LSE in the event a self-shown resource becomes unavailable, it would need to procure additional local area resources that it holds for this purpose, assuming the CPE contract allows the LSE to provide a replacement resource when on outage. If the CPE does not allow such a replacement, then the LSE self-showing may not want to take the risk that the outage of the resource will have the LSE pay backstop costs when the original showing mitigated CPE cost risk for all LSEs serving load in the local area. Simply put, the incentive to self-show and the potential consequences for self-showing would not align.

In the case that the CPE allowed an LSE to provide a replacement resource, the LSE would now need to procure additional local area resources potentially at a premium. Even if the replacement resource is not charging a premium, the LSE would need to procure the local resource and not show it as local, instead holding it as a potential replacement resource in the event another self-shown resource is on outage. This will then create additional scarcity of local area resources that may further the difficulty for the CPE in procuring sufficient resources within the local area to meet the local need. Therefore, CAISO's and PG&E's proposals would likely reduce the amount of self-shown resources offered to the CPE. Given this, the Commission should not adopt either proposal.

SCE proposes a process in which LSEs elect to self-show their resources to the CPE with an attestation and backstop costs due to not submitting self-shown resources on RA plans due to planned outages would be charged to the CPE and paid by all customers in the CPE's service territory. It appears SCE proposes any backstop costs not due to planned outages submitted between the annual and monthly RA showings without replacement would be charged directly to the LSE that did not show its self-shown resources in its RA plan.[10] SCE should clarify if outages within this timeframe is the intended proposal, given the CAISO also accepts planned outages after the monthly showings until seven days prior to the outage if substitute capacity is provided. While SCE's proposal creates less disincentives to self-show than PG&E's proposal, at the current rate of the local capacity requirement (LCR) reduction compensation mechanism (RCM) of at most $1.78/kW-month, any backstop risk from self-showing could disincentivize entities from self-showing.

The Commission must consider a market participant's alternatives in making a rule such as that proposed by SCE. An LSE has three options; 1) self-show and potentially receive LCR RCM if applicable; 2) offer the entire resource for sale to the CPE; or 3) not self-show or offer to sell to the CPE. In the case of the third option, while the LSE would be allocated its share of CPE costs which would not be reduced by the self-shown resource, the LSE would also not take on

10 *Phase 1 Proposals of Southern California Edison Company (U 338-E)*, Dec. 13, 2021 (SCE Proposals), at 3-5.

any risk of CPM backstop costs individually from the CAISO. Further, LSE's may not be eligible for LCR RCM either because there is no premium or because the resources does not qualify for the premium. In this case, the LSE is balancing a load ratio share of reduced CPE costs against a potential for backstop costs on a MW-for-MW self-shown basis at the CAISO CPM rate which is likely to be $6.31/kW-Month but could be higher or lower.[11] It is evident that for a small LSE, the potential savings in CPE costs by self-showing are minor compared to the potential for CPM costs to be allocated to them directly. Even in cases where the LCR RCM is available at a rate higher than $0, the incentive is still minimal as the highest LCR RCM value is $1.78/kW-month. With the CPM likely at $6.31/kW-month, that means that even in the highest paying LCR RCM area, a probability of outage greater than 28 percent yields an expected value lower than not self-showing due to the expected CPM costs that would be incurred.

Effectively, the SCE proposal makes the self-provision of a local resource carry a liquidated damages provision. While the LSE may be able to successfully replace the resource for its system showing, it may not be able to do so for the local attribute. Given that LSEs procuring local resources at this point are only doing so for system needs, it is unlikely that the LSE would have similar provisions in its contract with the supplier since the local risk would not have been a subject of the negotiation since the LSE did not have a local obligation. Without understanding the incentives or disincentives LSEs have for self-showing, it is not clear if SCE's proposal will reasonably resolve the existing issues with the self-showing process while not disincentivizing LSEs from self-showing.

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[11] The CAISO CPM has a soft-offer cap of $6.31/kW-Month but offerors may bid lower and are eligible for compensation in excess of this cap if they demonstrate to the Federal Energy Regulatory Commission that their costs are higher than the soft-offer cap.

Finally, even if this issue can be solved for the current instant, the Commission must keep in mind the incentives for the development of new local area resources. If any new resource procurement in a local area comes with the same risks discussed above, there will be significant disincentive for LSEs to develop new resources in local areas. This is because the LSE will have significant risk of realizing the local value of the resource through the LCR RCM given the risk of backstop costs that currently outstrips the LCR RCM value by a factor of three or more.

IV. THE COMMISSION SHOULD ADOPT PG&E'S PROPOSAL TO REMOVE CERTAIN SELECTION CRITERIA AND DATA SUBMITTAL REQUIREMENTS

CalCCA supports PG&E's proposal to revise the selection criteria in Ordering Paragraph (OP) 14 of D.20-06-002, and the data submittal requirements in OP 15 of D.20-06-002.[12] PG&E's proposal would remove certain selection criteria and data submittal requirements that may create unnecessary barriers to offering resources to the CPE. Certain operational characteristics requested by the CPE in the last solicitation are not accessible to LSEs. Further, these requirements may have contributed to LSEs and CPEs being unable to reach agreement on contract terms and conditions. For these reasons, the Commission should adopt PG&E's proposal.

V. THE COMMISSION SHOULD NOT REMOVE THE REQUIREMENT THAT UTILITIES BID IN AT THEIR LEVELIZED FIXED COSTS

PG&E[13] and SCE[14] propose to remove the requirement that investor-owned utilities (IOUs) must bid their resources at their levelized fixed costs. The Commission should not adopt this proposal. Allowing the IOUs to bid their resources at a value other than their levelized fixed costs would mean allowing the IOUs to charge CAM customers a different cost than the cost charged to PCIA customers, effectively transferring costs from one set of customers to another.

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12 *New Phase 1 Proposals of Pacific Gas and Electric Company (U 39 E) Regarding Central Procurement Entity Structure and Process*, Dec. 23, 2021 (New PG&E Proposals), at 1-5.

13 PG&E Proposals at 8-9.

14 SCE Proposals at 6-8.

In addition, the Commission originally approved the resource costs as reasonable for the IOUs customers to incur to serve their needs and hedge their future price risk. The PCIA then has retail access load pay for the above market costs of this hedge. Removing the levelized fixed cost requirement would provide the IOUs with the ability to bid their resources at prices that are unrestricted.[15] For these reasons, the Commission should not remove the requirement that the IOUs to bid their resources at their levelized fixed costs. If the Commission does decide to remove this restriction, it should not allow the IOUs to bid above the levelized fixed cost of the resource effectively capping the bids to ensure that the IOU stated intent of procuring local RA by the CPE at a lower cost is realized.

PG&E indicates the levelized fixed cost requirement is incompatible with the products being procured by the CPE and how the bundled procurement arm's portfolio is comprised, presenting a barrier to participating in the CPE process.[16] This implies that the IOU should be allowed to bid below the levelized fixed cost in order to reflect the only the RA value to compete with others that are offering on the RA value to the CPE. However, the Commission has long recognized that the IOUs may need to evaluate bids that are on a different basis included length of term and products offered. All source solicitations do exactly this. While PG&E notes the issue surrounding the allocation of RPS through CAM[17], this is not a sufficient reason to allow a tier 2 advice letter to formulate a new process for the costs that the IOU is allowed to bid in a CPE solicitation. If the Commission believes that a change from the levelized fixed cost is

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[15] While SCE at page 8 sites to potentially lower costs for customers from allowing bids that are not based upon the levelized fixed cost, SCE's proposal does not cap the IOU bids at levelized fixed costs meaning in times of scarcity, the IOU could bid above the levelized fixed cost and there is a possibility that the CPE would procure that resource causing customers to pay through CAM a level higher than what they otherwise would have paid in PCIA eliminating the hedge that was believed to have been procured by the IOU within the original contract.

[16] PG&E Proposals at 8.

[17] *Id.* at 8.

warranted, such a decision must be delivered through this OIR so that it is reasonably contemplated and so that proposals to address the concerns can be offered by more than just the IOU bundled procurement arm as suggested by PG&E.

VI. THE COMMISSION SHOULD ENSURE LSES ARE AWARE OF THEIR SYSTEM AND FLEXIBLE CAM ALLOCATIONS BY THE TIME THE SYSTEM AND FLEXIBLE REQUIREMENTS ARE ESTABLISHED IN JUNE

A. The Commission Should Allow the CPE to Solicit Local Resources Outside the All-Source Solicitation Process So Long as the Procurement is Complete and Allocated by the Time System and Flexible RA Requirements are Finalized in June

SCE proposes to allow the CPE to procure local resources outside the annual CPE solicitation, including "allowing the CPE to conduct procurement through other means, such as the broker markets or bilateral transactions, and on different timelines to meet local sub-area needs or other local needs that arise beyond the typical timeline for local capacity requirements."[18] CalCCA supports allowing the CPE to procure local resources outside the annual CPE solicitation. However, this procurement must be completed and RA quantities for system and flexible must be allocated to LSEs by the time the system and flexible RA requirements are finalized in June, so that LSEs know their system and flexible CAM allocations in time for them to complete their own procurement. CalCCA's proposal outlined a modified timeline for 2023 that would reach this objective.[19] Any procurement outside of an all-source solicitation should follow this proposed timeline and be communicated in supplemental compliance reports prior to the finalization of system and flexible RA requirements in June 2022.

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[18] SCE proposals at 8.
[19] CalCCA Proposals at 10-12.

B. The Commission Should Not Adopt PG&E's Proposed Timeline

PG&E recognizes LSEs need sufficient time to incorporate CPE procurement into their planning of their own system and flexible procurement.[20] However, its proposed timeline in which LSEs would receive their CAM credits for system and flexible RA procured by the CPE in mid-August does not allow LSEs enough time to effectively plan to meet their year-ahead obligations. CalCCA proposed that to fill the gap in local RA procurement for 2023, the timeline should allow the CPE to complete its all-source solicitations for 2023 by June so that allocations can be completed by the time LSEs receive their system and flexible requirements. Even this timeline encroaches on LSEs' ability to plan their system and flexible procurement, as many LSEs will begin procurement of 2023 system and flexible RA soon, if they have not already. For this reason, CalCCA proposed this timeline only to fill the significant gap in local procurement for 2023; in future years, local RA procurement should be completed by October, two years prior to the operational year.

Therefore, instead of adopting PG&E's proposal, the Commission should allow the CPE to conduct procurement outside the all-source solicitation process to speed up the procurement process for 2023 and adopt the timeline proposed by CalCCA that would communicate system and flexible credits to LSEs by the time their RA requirements are finalized in June. If the CPE cannot effectively conduct another all-source and complete the solicitation by June to procure for 2023, the CPE should instead solicit additional procurement outside the all-source solicitation process as discussed in section A above.

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20 New PG&E Proposals at 5.

VII. CPE CONFIDENTIALITY PROVISIONS SHOULD BE CONSISTENT WITH D.06-06-066

In its proposal, PG&E provides a table summarizing its proposal for confidential treatment of CPE information which deviates from D.06-06-066 in some areas. Under the category of "Contract Terms and Conditions," PG&E proposes contracts and power purchase agreements be confidential for a period of the later of three years from delivery start or one year after execution.[21] This should be clarified, consistent with D.06-06-066, to specify that contract summaries are public, including counterparty, resource type, location, capacity, expected deliveries, delivery point, length of contract and online date.[22]

Under the category "Forecast," PG&E proposes "Forecasted RA Requirements" and "Allocations (MW)" be confidential for three years. PG&E's justification for keeping this information confidential is, "Disclosure of the capacity that is forecasted to be sold in each local area could potentially have an adverse effect on the market, put the CPE at a competitive disadvantage with regard to other market participants, and impact participants' future bidding behavior for capacity that has not yet been procured."[23] This justification is not clear given the description of the item is related to forecasted requirements and allocations rather than capacity sales. Forecasted requirements are published by the Commission three years forward, and the CPE is allocated all the local RA requirements. Additionally, aggregate CAM allocations are published and should continue to be published so LSEs are aware of their own procurement obligations. Therefore, it is not clear what the forecasted requirements and allocations are that PG&E is proposing to keep confidential. The Commission should ensure CPE confidentiality provisions are consistent with those outlined in D.06-06-066.

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21 PG&E Proposals at A-1.
22 D.06-06-066 at Appendix 1, p 15.
23 PG&E Proposals at A-3.

VIII. CONCLUSION

For all the foregoing reasons, CalCCA respectfully requests consideration of these comments and looks forward to continuing the dialogue with the Commission and stakeholders around the CPE framework.

Respectfully submitted,

Evelyn Kahl

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

January 4, 2022

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

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION RESOLVING PHASE 2 ISSUES RELATED TO ENERGY RESOURCES RECOVERY ACCOUNT PROCEEDINGS

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January 6, 2022

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION RESOLVING PHASE 2 ISSUES RELATED TO ENERGY RESOURCES RECOVERY ACCOUNT PROCEEDINGS

The California Community Choice Association (CalCCA)[1] submits these comments pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure on the proposed *Decision Resolving Phase 2 Issues Related to Energy Resources Recovery Account Proceedings* (Proposed Decision or PD), mailed on December 17, 2021.

I. INTRODUCTION

But for one issue discussed below, CalCCA fully supports the Proposed Decision and thanks the Commission for its careful consideration of the impact on the Energy Resource Recovery Account (ERRA) cases of matters decided in this proceeding. CalCCA and its members look forward to working with the investor-owned utilities (IOUs) to implement the PD's orders smoothly and expeditiously. We also look forward to the Commission's

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1 California Community Choice Association represents the interests of 22 community choice electricity providers in California: Apple Valley Choice Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

consideration and decision regarding the remaining Power Charge Indifference Adjustment (PCIA) components.

However, as currently written, one issue could defeat the purpose of the proposed changes. The PD should direct that each ERRA proceeding's schedule require the IOUs to provide their updated prepared testimony no later than 14 days following the issuance of the market price benchmarks (MPB) on October 1st. In addition, an apparent typographical error should be corrected to clarify that Southern California Edison Company's (SCE's) data disclosure requirements do not require modification at this time.

II. FACTUAL, LEGAL, AND TECHNICAL ERRORS AND CLARIFICATIONS

A. The IOUs Should be Directed to Provide Updated Testimony No Later than 14 Days After the MPB Date

As the PD describes, the purpose of the staff proposal moving the MPB date (MPB Date) from November to October 1 was "to enable the Commission to direct utilities in the ERRA forecast proceedings to provide updated prepared testimony in October (an October Update) rather than in November."[2] Although it adopts the staff proposal for the MPB Date, the PD lacks explicit direction regarding the *deadline* for the important October Update. The current practice in the ERRA forecast proceedings is for the MPB to be released on November 1, and for the IOU Updates to be filed shortly thereafter. To give parties adequate time to evaluate the IOUs' calculation and prepare to set rates accordingly, the PD should explicitly direct the IOUs to file their October Update within 14 days of the October 1st MPB Date.

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2 PD at 6.

It is clear the PD intends to leave scheduling of the ERRA proceedings to each individual ERRA forecast proceeding's Assigned Commissioner and ALJ.[3] However, a direction setting the parameters for the October Update does not unduly restrict their discretion. An outside deadline for the October Update is similar to the deadline for filing ERRA forecast applications the PD considered and ordered.[4] Establishing the outside date for the October Update in this proceeding leaves discretion with the Assigned Commissioner and ALJ in each ERRA proceeding to consider utility-specific and fact-specific circumstances, while still guaranteeing parties the benefit of the change to the MPB Date established in the PD.

B. The PD Should Clarify that No Changes are Required to SCE's ERRA Data Disclosure Requirements

As the PD indicates, parties agree that SCE's and PG&E's ERRA/PABA data requirements are substantially the same.[5] While the PD states "there is no reason to modify PG&E's ERRA data disclosure requirements,"[6] the PD fails to mention SCE in this context. The PD should clarify that SCE's ERRA data disclosure requirements also do not require modification at this time.

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3 *Id.* at 12 ("The Commission will not establish ERRA forecast proceeding schedules in this decision. As noted in the ALJ ruling on May 20, 2021, the assigned Commissioner and assigned ALJ in each ERRA forecast proceeding are responsible for setting the schedule for the proceeding.").

4 *Id*. at 4 and Ordering Paragraph 3 at 27.

5 *Id.* at 16.

6 *Id*. at 17.

III. CONCLUSION

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

Respectfully submitted,

__/s/_*Ann Springgate*________________
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ATTACHMENT A

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

FINDINGS OF FACT

no changes

CONCLUSIONS OF LAW

no changes

ORDERING PARAGRAPHS

1. The California Public Utilities Commission will release the Market Price Benchmarks for the Power Charge Indifference Adjustment by October 1st each year or the first business day thereafter if October 1st is on a Saturday or Sunday. <u>The utilities will be required in each ERRA proceeding to file their prepared testimony within 14 days of the release of the Market Price Benchmarks</u>.

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

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

**REPLY COMMENTS OF
THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION
ON ALJ RULING REGARDING PCIA FORECASTING DATA ACCESS**

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On behalf of
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January 6, 2022

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

REPLY COMMENTS OF
THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION
ON ALJ RULING REGARDING PCIA FORECASTING DATA ACCESS

Pursuant to Administrative Law Judge (ALJ) Wang's November 5, 2021 e-mail ruling (ALJ Ruling), the California Community Choice Association[1] (CalCCA) hereby submits these comments to respond to and correct certain misleading statements in the investor-owned utilities' (IOUs') opening comments.[2] The IOUs insist that the Commission should not permit the disclosure of confidential market sensitive procurement data to the community choice aggregators (CCAs). The IOUs also state that CalCCA's data transparency proposal would require the Commission to put CCA decisionmakers' interests over those of consumers. To the contrary, CalCCA's proposal would put unbundled customers on equal footing with bundled customers and afford the CCAs the same ability to protect its customers against rate volatility

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1 California Community Choice Association represents the interests of 22 community choice electricity providers in California: Apple Valley Choice Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

2 *Joint Response of Pacific Gas and Electric Company (U 39E), Southern California Edison Company (U 338E), and San Diego Gas & Electric Company (U 902E) to Administrative Law Judge's Ruling Requesting Comments on PCIA Forecasting Data Access (Joint IOU Opening Comments),* R.17-06-026 (Dec. 9, 2021).

that IOUs already enjoy. Further, CalCCA's proposal would not permit the CCA's reviewing representatives (RRs) to disclose confidential data that is not already disclosed in public filings in the IOUs' Energy Resource Recovery Account (ERRA) Forecast proceedings. CalCCA therefore reiterates its request that the Commission adopt its reasonable data transparency proposal as detailed in its opening comments.[3]

I. CALCCA'S DATA TRANSPARENCY PROPOSAL DOES NOT RISK THE DISCLOSURE OF CONFIDENTIAL DATA TO MARKET PARTICIPANTS

In their opening comments, the IOUs repeatedly caution the Commission that market participants should not receive market sensitive procurement and/or forecasting data to support rate forecasting or business planning activities.[4] The IOUs state that if a market participant were to receive market sensitive information, they might "use that information to gain a material advantage in transactions, planning, or procurement strategies."[5] The IOUs assert that the disclosure of market sensitive information to market participants "can materially impact the market price of electricity" and would be "inconsistent with the Commission's statutory obligations to protect IOUs' market sensitive procurement information . . . and Commission precedent, and introduces a significant risk of competitive harm to IOU customers."[6]

The IOUs' warnings are misleading because CalCCA does not propose that the CCAs or any other market participant receive confidential market sensitive procurement data. Rather,

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3 *See Opening Comments of The California Community Choice Association on ALJ Ruling Regarding PCIA Forecasting Data Access (CalCCA Opening Comments),* R.17-06-026 (Dec. 9, 2021).

4 *See, e.g., Joint IOU Opening Comments* at 2, 4, 7.

5 *Id.* at 4.

6 *Id.* at 2.

CalCCA proposes that RRs receive confidential information and disclose only summary level revenue requirements, forecasted PCIA rates, and the drivers underlying those rates to the CCAs.[7] This is the same process already followed in their annual ERRA proceedings, and under CalCCA's proposal the market participants would only have access to the *same type of* aggregated (not resource-specific) information that the IOUs already disclose in their public filings as a part of their annual ERRA Forecast proceeding.[8] CalCCA simply proposes that the IOUs should make such information available year-round, and outside the ERRA Forecast proceeding, rather than keeping CCA customers in the dark for half of the year. RRs, who *would* receive confidential information under CalCCA's proposal would be subject to the same rigorous process that mitigates the risk of the disclosure of confidential data in the IOUs' ERRA proceedings. The IOUs' suggestion that CalCCA's proposal would somehow result in the disclosure of confidential market-sensitive procurement data to market participants—and thereby create incremental risk to customers—is not factual, and the Commission should reject it.

II. THE IOUS MISCHARACTERIZE THE OBJECTIVES OF CALCCA'S DATA TRANSPARENCY PROPOSAL

The IOUs suggest that CalCCA's proposal requires the Commission to weigh "the risk of customer harm" against "vague claims of educational benefit."[9] The IOUs also "urge the Commission to place customer protections before the needs of any DA or CCA decisionmaker."[10] Moreover, the IOUs assert that "[i]t is poor public policy to introduce the risk of customer harm through increased costs or other anti-competitive effects in exchange for

[7] *See CalCCA Opening Comments* at 21.
[8] *See id.* at 22.
[9] *Joint IOU Opening Comments* at 2.
[10] *Id.* at 3.

alleged improvements to a CCA or DA provider's internal processes and/or ability to develop or understand rate or balancing account forecasts through access to market sensitive data."[11]

The IOUs' comments misleadingly pit "customers" against "CCA decision makers." They ignore that the whole point of CalCCA's data transparency proposal is to *protect* unbundled customers (who, it should be noted, are also IOU customers). As CalCCA explained in opening comments, the CCAs, like all load serving entities (LSE), strive for rate stability for their customers.[12] However, CCAs cannot provide the same rate stability as the IOUs under the Commission's current data confidentiality framework, which unfairly advantages IOUs. A year-round Non-Disclosure Agreement (NDA), as proposed by CalCCA, would give CCAs the ability to plan around volatility in the Power Charge Indifference Adjustment (PCIA) and protect unbundled customers from rate spikes. It does not require the IOUs to disclose any confidential data to market participants that would put bundled customers at risk of harm. There is therefore no conflict between consumer protections and the CCAs' need to plan and forecast rates; in fact, the two objectives are aligned. The Commission need not pick between the two as the IOUs falsely suggest.

III. CONCLUSION

For the reasons set forth in CalCCA's opening comments and previously-filed comments in this proceeding, CalCCA respectfully requests that the Commission adopt its data transparency proposal, and authorize an NDA that provides CCAs' RRs (and the reviewing representatives of other entities with customers who pay the PCIA) access to the following data year-round:

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11 *Id.*at 2-3.

12 *See CalCCA Opening Comments* at 2-3.

- The confidential versions of the IOUs' Monthly Reports for each month of the year at the same time such confidential versions are provided to the Commission;

- The data and workpapers underlying those Monthly Reports, at the same level of granularity and within the same schedule, that is now required to be provided as part of ERRA Forecast proceedings in each IOU service territory; and

- The workpapers underlying PCIA rates that the IOUs have provided within the prior year's ERRA Forecast proceedings as part of either the November Update or an advice letter implementing the final decision in the ERRA Forecast proceeding.

Respectfully submitted,

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

In The Matter of Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2022 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation. (U 39 E)	Application 21-06-001 (Filed June 1, 2021)

PACIFIC GAS AND ELECTRIC COMPANY (U-39 E), THE DIRECT ACCESS CUSTOMER COALITION, JOINT CCAS AND THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION, AND THE PUBLIC ADVOCATES OFFICE PARTY STATEMENTS CONCERNING ADDITIONAL ERRA-MAIN DATA

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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In The Matter of Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2022 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation. (U 39 E)	Application 21-06-001 (Filed June 1, 2021)

PACIFIC GAS AND ELECTRIC COMPANY (U-39 E), THE DIRECT ACCESS CUSTOMER COALITION, JOINT CCAS AND THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION, AND THE PUBLIC ADVOCATES OFFICE PARTY STATEMENTS CONCERNING ADDITIONAL ERRA-MAIN DATA

I. INTRODUCTION AND BACKGROUND

Pursuant to the December 17, 2021 Ruling of Administrative Law Judge Lee ordering Pacific Gas and Electric Company ("PG&E") to file additional data concerning the amortization of PG&E's Year-End Energy Resource Recovery Account ("ERRA")-Main balance, and directing parties to meet-and-confer concerning such additional data ("Ruling"), PG&E, the California Community Choice Association ("CalCCA"), the Direct Access Customer Coalition ("DACC"),[1/] Joint CCAs,[2/] and the Public Advocates Office at the California Public Utilities Commission ("Cal Advocates") offer party statements to the California Public Utilities Commission ("Commission") through this pleading for consideration.[3/]

1/ DACC is a regulatory advocacy group comprised of educational, governmental, commercial and industrial customers that utilize direct access for all or a portion of their electrical energy requirements.

2/ The "Joint CCAs" consist of Central Coast Community Energy, the City and County of San Francisco, East Bay Community Energy, Marin Clean Energy, Peninsula Clean Energy Authority, Pioneer Community Energy, San José Clean Energy, Silicon Valley Clean Energy Authority, and Sonoma Clean Power Authority.

3/ Pursuant to Rule 1.8 (d) of the Commission's Rules of Practice and Procedure counsel for Cal Advocates, CalCCA, DACC, and the Joint CCAs have authorized PG&E to file this pleading on their behalf.

On December 28, 2021 PG&E filed and served its Fifth Supplemental Testimony, marked as Exhibit PGE-9, in compliance with the Ruling. PG&E's Fifth Supplemental Testimony provided updated revenue requirements, rate impacts, and bill impacts associated with amortizing over 18 months and over 24 months the forecast end-of-the year ERRA-Main balance, as filed in the December Update, that PG&E requests to be transferred to the 2021 Portfolio Allocation Balancing Account ("PABA") subaccount.[4/] In PG&E's December Update, PG&E presented updated revenue requirements, rate impacts, and bill impacts that amortize the forecast end-of-the year ERRA-Main balance over 12 months. The December Update used recorded accounting close balances up to and including November 30, 2021 and used energy market forecasts as of November 30, 2021 for December 2021 balances.

On January 4, 2021, parties to PG&E's 2022 ERRA Forecast proceeding participated in a remote meet-and-confer meeting concerning the additional data and amortization scenarios. All parties to Application (A.) 21-06-001 were present at the remote meeting, with representatives of the Applicant PG&E and the following parties were present:

- Agricultural Energy Consumers Association;
- California Community Choice Association;
- California Farm Bureau Federation;
- California Large Energy Consumers Association;
- Direct Access Customer Coalition;
- Joint CCAs; and
- Public Advocates Office at the California Public Utilities Commission

II. PARTY STATEMENTS

In this below section, PG&E and certain individual parties to A. 21-06-001 offer individual party statements concerning the additional data and amortization scenarios presented

4/ PG&E's December Update was filed and served on December 14, 2021 and was marked as Exhibit PGE-7.

in PG&E's Fifth Supplemental Testimony. Each subsection was developed by the party specified therein, without subsequent modification by PG&E.

A. Pacific Gas and Electric Company

PG&E has considered the additional data provided in the Fifth Supplemental Testimony as part of the development of this party statement. Based on the additional information and data, PG&E respectfully requests that the Commission issue a Proposed Decision authorizing a 12-month amortization of the forecast year-end 2021 balance, as set forth in the rate proposals in Appendix B to PG&E's December Update. Pursuant to the rate proposals set forth in PG&E's December Update, PG&E amortizes the forecast year-end balance in 2022 rates. Amortization of the ERRA-Main balance over 12-months is consistent with the past recoveries of both undercollections and overcollections of PG&E's ERRA-related balancing account and provides for timely recovery of PG&E's electric procurement costs incurred pursuant to a Commission-approved procurement plan, consistent with California Public Utilities Code Section 454.5 (d)(3). PG&E's Assembly Bill 57 framework provides for a mechanism to adjust bundled customer generation rates in 2022 if necessary. PG&E's 2022 ERRA balances would inform whether PG&E would need to file an ERRA Trigger application in 2022 to adjust rates.

As described in December 28 Testimony, the adoption of an 18- or 24-month amortization period year-end balance introduces costs and risk to PG&E and its customers. Timely cost recovery of PG&E's incurred procurement costs is an important credit rating consideration. A longer amortization period for PG&E's ERRA-Main costs in this proceeding would result in delays to cost recovery of PG&E's incurred costs and would have negative credit implications for PG&E. PG&E's customers are negatively impacted by adverse credit events because such events can result in lower credit ratings and higher borrowing costs for PG&E, ultimately resulting in higher costs to customers.

In addition to the potential credit implications associated with 18- or 24-month amortization, a longer amortization period will increase costs to customers in two direct ways: first, customers must pay interest on the balancing account undercollections for the longer period that they would be outstanding relative to a 12-month amortization. Second, a delay in recovering PG&E's ERRA-Main undercollection was not contemplated in the sizing of PG&E's liquidity facilities that support short-term financing. As such, PG&E may need to seek incremental lending capacity to support electric procurement costs. The cost of the bank fees associated with that incremental capacity would be passed through to customers as well. Accordingly, customers would ultimately face higher costs if a longer amortization period for the ERRA-Main balance is adopted by the Commission, either directly through higher short-term interest and bank facility fees or indirectly if a longer amortization period contributed to a ratings downgrade. PG&E urges the Commission to maintain timely cost recovery based on 12-months of billed revenues to provide PG&E timely cost recovery of its costs incurred pursuant to a Commission-approved procurement plan, and to avoid negative financial consequences for the utility and its customers.

B. California Community Choice Association and the Joint CCAs

CalCCA and the Joint CCAs support a 12-month amortization of the revenue requirements presented in the December Update. Both parties also continue to endorse and hereby incorporate the statements made in the Joint CCAs' December 20, 2022 comments in response to the December Update.[5/] As more fully explained in those comments, the Commission should approve PG&E's proposed forecasted revenue requirements and associated rates in its December Update because those proposals are reasonable and are in compliance with all applicable rules, regulations, resolutions and decisions for all customer classes. Moreover, the Commission should avoid any further delay in the implementation of 2022 rates because such delays will harm all customers by increasing rate volatility. Lastly, the Commission should not take any action on the October Update because it reflects actual costs and revenues from only nine months out of the year and therefore does not comply with statute or Commission precedent.

5/ A.20-06-001, *Comments of the Joint Community Choice Aggregators*, p. 2 (Dec. 20, 2021).

C. Direct Access Customer Coalition

DACC concurs with PG&E that the amortization of the ERRA-Main balance over 12-months is consistent with the past recoveries of both undercollections and overcollections of PG&E's ERRA-related balancing account and provides for timely recovery of PG&E's electric procurement costs incurred pursuant to a Commission-approved procurement plan, consistent with California Public Utilities Code Section 454.5 (d)(3).

D. Cal Advocates

The Public Advocates Office at the California Public Utilities Commission (Cal Advocates) does not oppose Pacific Gas and Electric Company's (PG&E) proposed 12-month amortization period for the approved 2022 Energy Resource Recovery Account (ERRA) Forecast Application (A.)21-06-001 (2022 ERRA Forecast) revenue increase.

Recovering the proposed 2022 ERRA Forecast revenue increase over 18 or 24 months would not appreciably reduce rates and bills for PG&E customers in 2022. If an extended recovery period of 18 or 24 months is approved, only a portion of the revenue contained within the main ERRA balancing account would be amortized over either extended period. Cal Advocates estimates recovery over an 18-month amortization period would reduce bundled residential and small commercial average rates by less than 2% compared to rates calculated over a 12-month recovery period. Further, amortizing recovery over 24 months would reduce bundled residential and small commercial average rates by slightly more than 2% compared to rates calculated over a 12-month recovery period. The balance of revenues not recovered in 2022 under the extended amortization periods would instead be recovered from customers in 2023.

Recovering the proposed 2022 ERRA Forecast revenue increase over 18 or 24 months would only provide temporary rate relief, because rate recovery of the remaining ERRA Forecast balance in 2023 would coincide with significant, additional, rate increases from other pending applications. Concurrently in 2023, PG&E customers may see rate increases from the following currently pending applications: (1) PG&E's Test Year (TY) 2023 General Rate Case Phase 1

(A.21-06-021); (2) PG&E's 2020 and 2021 Wildfire Mitigation and Catastrophic Events (A.20-09-019, A.21-09-008); and (3) PG&E's 2018 Catastrophic Event Memorandum Account (A.18-03-015). There may also be additional unforeseen revenue and rate changes in 2023 from future applications not yet filed, such as PG&E's 2023 ERRA Forecast Application. Recovery of the 2022 ERRA Forecast balance under the 18- and 24-month amortization scenarios, in addition to the previously listed applications, will result in larger, cumulative 2023 rates for all customers. Conversely, recovering the full 2022 ERRA Forecast revenue increase over 12 months would mitigate the potential cumulative rate increases PG&E customers are expected to face in 2023 by minimizing the anticipated overlapping recovery period.

III. CONCLUSION

PG&E and the parties represented herein request that the Commission consider the foregoing party statements in the development of a Proposed Decision addressing PG&E's 2022 ERRA Forecast rate requests.

Respectfully Submitted,

By: *<u>/s/ Maria V. Wilson</u>*
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Dated: January 6, 2022

Submit comment on Draft final proposal and draft tariff language

Initiative: Transmission service and market scheduling priorities

The comments below are submitted jointly on behalf of the Bay Area Municipal Transmission Group, the California Community Choice Association, the Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California (collectively, the Six Cities), Pacific Gas and Electric Company, and San Diego Gas & Electric Company. The comments below refer to the entities submitting these comments as "Joint CA LSEs."

1. Please share your organization's overall position on the Phase 1 draft final proposal.

Choose:

- Support
- <u>Support with caveats</u>
- Oppose
- Oppose with caveats
- No position

2. Please share your organization's perspective on the Phase 1 proposed extension of the wheeling through priorities and associated framework for the next two summers, through Jun 1, 2024.

<u>The CAISO should make the completion of the remainder of this initiative a high priority in 2022.</u>

The Joint CA LSEs support the CAISO's proposal to extend the interim wheeling-through scheduling priorities framework approved by FERC and currently in effect, which otherwise would expire on June 1, 2022. FERC found these scheduling priorities to be just and reasonable on an interim basis, not unduly discriminatory, and consistent with open access principles. Reverting to the previously effective priorities would be unjustified.

The CAISO should make the completion of the remainder of this initiative a high priority in 2022. As such, the CAISO should consider accelerating the current Phase 2 timeline in order to open up the possibility of implementing elements of the long-term scheduling priorities framework as soon as summer 2023. The proposed two-year extension of interim scheduling priorities to June 2024 should not preclude the CAISO from striving to develop and implement remaining elements of this initiative before then. One approach to accelerating the process could be revising the Phase 2 timeline to target submitting the proposal to the CAISO Board and EIM Governing Body by August 2022, rather than December 2022.[1] We believe a modified timeline could enable the implementation of elements of the long-term scheduling priorities framework as soon as summer 2023.

The Joint CA LSEs understand the need to provide certainty for entities outside of the CAISO BAA and to set a realistic timeline for developing and implementing a new transmission reservation process. But while the interim scheduling priorities framework constitutes a significant improvement over the priorities structure previously in effect, the interim framework nevertheless falls short of providing CAISO BAA customers with reliability and native load protections that are on par with those of other BAAs. The interim framework also does not include a rate structure that ensures wheeling customers electing to obtain high priority wheeling access are contributing to the revenue requirement for the CAISO transmission system in a manner that is commensurate with receiving priority comparable to native load. The Joint CA LSEs believe that, in the subsequent phase of this initiative, the CAISO can and should consider implementing improvements to the interim scheduling priorities framework earlier than two-and-one-half years from now, as well as accelerating the process to develop and begin implementation of the long-term framework.

3. Please share your organization's perspective on other proposed elements of the Phase 1 draft final proposal, and any other aspects of the Phase 1 draft final proposal.

The CAISO should take further actions to ensure high priority (PT) exports do not exceed the non-RA capacity of designated supporting resources

The Joint CA LSEs appreciate the CAISO's attention to concerns regarding instances in which PT export schedules could exceed the non-RA capacity of the designated supporting resource. The Draft Final Proposal includes improvements that should help mitigate the risk of underproducing or physically unavailable resources supporting PT exports. These improvements include:

1) Creating new technology functionality in the Scheduling Infrastructure Business Rules (SIBR) system to provide scheduling coordinators for both the exporters and designated supporting resources with more visibility into the resource's non-RA capacity and ability to support a PT export.
2) Updating the CAISO tariff to require that the "most recent forecast" for VERs supporting PT exports, rather than the forecast at the time of bid submission, is equal to or greater than the PT export quantity.

While these are positive steps, the Joint CA LSEs disagree with the CAISO's decision to forego the opportunity to create flexibility for the CAISO to make adjustments to PT export schedules in cases in which they exceed the non-RA capacity of the supporting resource and in order to maintain reliability.[2] We urge CAISO to reconsider its current proposal and consider ways to provide flexibility

[1] See proposed Phase 2 schedule at pp. 31-32 of Draft Final Proposal: http://www.caiso.com/InitiativeDocuments/DraftFinalProposal-TransmissionService-MarketSchedulingPriorities.pdf

[2] The DMM has commented that "allow[ing] curtailment of PT exports before CAISO load when availability or production capability of the designated supporting resource is observed to be less than the quantity of the associated PT export … would better align with DMM's understanding of the practices of other BAAs, which may curtail exports associated with a specific resource in order to maintain reliability if the resource is unavailable to support the export." California ISO Department of Market Monitoring, "Comments on External Load Forward Scheduling Rights Initiative Issue Paper (Sept. 30, 2021),

in the tariff to adjust PT export schedules, particularly in instances when the PT export can no longer be supported due to changes in the availability of the supporting resource and the CAISO BAA's reliability is at risk. We also request that CAISO monitor and report instances in which PT exports exceed the available non-RA capacity of the designated supporting resources.

CAISO should clarify the definition of non-RA capacity

The Joint CA LSEs request clarification of non-RA capacity values that are used in determining the quantity that may support a PT export. Specifically, we ask the CAISO to address the comments made by the CPUC Energy Division on the December 20, 2021 stakeholder call that identified a potential discrepancy in the definition of "non-RA capacity" between the CAISO Tariff and the CAISO market software. We would appreciate clarification of this issue and how defining non-RA capacity as the amount above the NQC for hydro resources or the ELCC NQC for wind and solar resources would impact the amount of capacity that can be used to support PT exports.

Transparency enhancements should include monthly reporting of wheeling revenues from PT wheel through transactions

The Joint CA LSEs appreciate and support the CAISO's publication of regular data related to wheel through and export transactions on the CAISO system. We request that the CAISO also provide monthly reporting of wheeling revenues from PT wheeling transactions.

4. Please share your organization's perspective on the proposed draft tariff language on Phase 1 elements.

The CAISO should clarify the meaning of "the most recent forecast" for Variable Energy Resources supporting PT exports

The CAISO proposes to modify section 30.5.1(aa) to include a reference to a Variable Energy Resource's "most recent forecast." We would appreciate clarification of which forecast this refers to.

5. Please share your organization's perspective on the Phase 2 direction and information update, including the associated timeline for the phase.

As discussed under Item 2 above, the Joint CA LSEs are concerned that the extended timeline for this initiative contemplated in the CAISO's proposal will unduly prolong elements of the interim priorities framework that fail to provide CAISO BAA customers with reliability and native load protections that are on par with those of other BAAs. To mitigate such impacts, in the subsequent course of this initiative, the CAISO should be open to accelerating the Phase 2 schedule for the long-term scheduling priorities framework and considering implementation of improvements to the interim framework earlier than two-and-one-half years from now. The CAISO should attach high priority to completion of this initiative by the end of 2022. In no event should the proposed timeline delay implementation of improvements to the priorities structure beyond June 1, 2024.

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available at https://stakeholdercenter.caiso.com/Comments/AllComments/61b0d47d-74ba-4d26-97d5-74468db1e99c#org-08196aef-854f-41a7-b1da-f68eec95dc5a

California Community Choice Association

SUBMITTED 01/10/2022, 02:31 PM

Contact
Shawn-Dai Linderman (shawndai@cal-cca.org)

1. Please share your organization's overall position on the revised draft final proposal:

SUPPORT

The California Community Choice Association (CalCCA) appreciates the opportunity to submit comments on the Revised Draft Final Proposal (Draft Proposal) in the Energy Imbalance Market (EIM) Resource Sufficiency Evaluation (RSE) Enhancements Initiative.[1] CalCCA is supportive of the efforts of the California Independent System Operator (CAISO) to adopt enhancements to the RSE to ensure that the RSE is administered accurately and applied equitably. CalCCA supports the proposed two-phased approach of implementing enhancements developed with stakeholder input in Phase 1 on an expedited basis, and then evaluating the success of such enhancements in an upcoming Phase 2.

In particular, CalCCA supports the delay of any consideration of RSE failure consequences to Phase 2 -- after the implementation of the enhancements. As CalCCA has stated in its prior comments in this initiative, CalCCA opposes financial or additional operational consequences (beyond the current capping of incremental upward EIM transfers) for failing the RSE, as such consequences will have adverse impacts on the EIM, a voluntary market, by hindering EIM participation beyond what is necessary to avoid leaning.

EIM entities can voluntarily elect to participate in and make supply available to the EIM through the base scheduling process. EIM participants already face existing penalties for non-compliance with responsibilities in the Balancing Area Authority. In addition, the CAISO's market process clears supply with forecasted demand. To do this, resource adequacy resources have a must offer obligation to ensure sufficient offers are made available to the market to meet forecasted demand. Any financial consequences for failure of the RSE could dissuade entities from fully participating in the EIM to avoid the risk of incurring financial penalties.

In addition, operational consequences beyond the current capping of incremental upward EIM transfers to prevent leaning should not be considered. Any such operational consequences could exacerbate reliability challenges if a decrease in the transfer limit occurs when an entity is already experiencing reliability challenges.

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[1] *EIM Resource Sufficiency Evaluation Enhancements Phase 1, Revised Draft Final Proposal,* Dec. 16, 2021 (Draft Proposal).

2. Please share your organization's perspective regarding the proposal to suspend the intertie deviation uncertainty adder:

No comments at this time.

3. **Please share your organization's perspective regarding the proposal to use its FERC authority to suspend the net-uncertainty adder in the capacity test:**

   No comments at this time.

4. **Please share your organization's perspective regarding the proposal to remove any penalties intended to prevent misuse of the demand response functionality:**

   CalCCA supports further analysis (in Phase 2) of how to incorporate demand response into the RSE. The removal of any proposed enhancements to classify expected demand response participation through forecast adjustments, which could trigger the automatic application of the under-scheduling tests, is appropriate. CalCCA agrees with the CAISO that any consequences for potential misuse of demand response must only be developed after stakeholder input and further CAISO analysis. In general, CalCCA opposes any financial penalties or additional operational consequences outside of the current capping of incremental EIM transfers.

5. **Please share your organization's perspective regarding the proposal to make configurable the amount of capacity that will be counted in the capacity test for resources who unavailable due to prior market decisions:**

   No comments at this time.

6. **Please share your organization's perspective on its proposal to expand the operator actions that correspond to resource insufficiency:**

   No comments at this time.

7. **Please share your organization's perspective regarding the proposal to expand the interchange reliability accounting, to account for both import and exports:**

   No comments at this time.

8. **Please provide your organization's perspective on additional scope items, not already identified in the paper, that the ISO should include in phase 2 of the RSEE initiative:**

   No comments at this time.

9. **Please provide any additional comments on the EIM RSE Enhancements initiative that have not previously been addressed:**

   No comments at this time.

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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'S REPLY COMMENTS ON THE PROPOSED DECISION RESOLVING PHASE 2 ISSUES RELATED TO ENERGY RESOURCES RECOVERY ACCOUNT PROCEEDINGS

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California Community Choice Association

January 11, 2022

SUBJECT MATTER INDEX

I. THERE IS NO EVIDENCE OR ANALYSIS SUPPORTING THE ARGUMENT THAT INCREMENTALLY "EARLIER" MARKET PRICE DATA WILL LEAD TO LESS ACCURACY IN FORECASTING AND POTENTIAL RATE INSTABILITY 1

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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'S REPLY COMMENTS ON THE PROPOSED DECISION RESOLVING PHASE 2 ISSUES RELATED TO ENERGY RESOURCES RECOVERY ACCOUNT PROCEEDINGS

The California Community Choice Association (CalCCA)[1] submits these comments pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure on the proposed *Decision Resolving Phase 2 Issues Related to Energy Resources Recovery Account Proceedings* (Proposed Decision or PD), mailed on December 17, 2021.

I. THERE IS NO EVIDENCE OR ANALYSIS SUPPORTING THE ARGUMENT THAT INCREMENTALLY "EARLIER" MARKET PRICE DATA WILL LEAD TO LESS ACCURACY IN FORECASTING AND POTENTIAL RATE INSTABILITY

The Opening Comments of Southern California Edison Company (SCE), Pacific Gas and Electric Company (PG&E), and San Diego Gas & Electric Company (SDG&E) (collectively, the Joint Utilities) argue that the PD's changes to the date of the Energy Resource Recovery Account (ERRA) Application and to the November (now October) Update will lead to less accuracy in forecasting and increase the potential for rate instability:

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1 California Community Choice Association represents the interests of 22 community choice electricity providers in California: Apple Valley Choice Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

> [T]he PD does little to address the PCIA calculation's current forecasting shortcomings and customer rate instability. To the contrary, if the PD is adopted as is, it would instead likely exacerbate them.[2]

The Joint Utilities claim moving the November Update back to October will require reliance on September forward-market data, which is, according to the Joint Utilities, "less indicative of the following year's actual market prices [than] the October data the Commission currently relies upon."[3] In addition, the Joint Utilities assert that issuing an October Update "may exclude procurement costs from the [investor owned utilities' (IOUs')] annual Resource Adequacy (RA) Year-Ahead Solicitations, because the IOUs' Year-Ahead RA plans are filed around October 31st every year."[4]

The Joint Utilities' bald assertions simply do not justify overriding the PD's conclusions. The PD bases its determinations on parties' comments and the ED staff's analysis of the probable effects of moving the Update to October (MPB Staff Analysis).[5] That analysis concludes that "moving the Update forward will likely have a minor impact on forecasted and final MPB values and PCIA values and should not result in PCIA rate instability."[6] As the PD notes, most parties agree with this conclusion.[7] Several parties agree that the best way to ascertain the true impact of these changes will be a "post hoc analysis conducted over the next few years."[8] This is exactly what the PD orders.[9] The Joint Utilities do not present any further analysis on the potential impact of the data they have identified as "missing." Instead, their arguments are simply unjustified assertions regarding issues that have already been considered.

In addition, any forecast inaccuracies due to the earlier Update will be trued up by actual revenues as part of the PCIA calculation process. Thus, to change the resultant PCIA, the "missing" information must have such an impact that it cannot realistically be "trued up." The Joint Utilities have presented no data or analysis indicating that the "missing" information would materially impact the final PCIA.

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2 R.17-07-026, *The Joint Utilities' Opening Comments on Proposed Decision Resolving Phase 2 Issues Related to Energy Resources Recovery Account Proceedings* (Jan. 6, 2022) (Joint Utilities' Opening Comments), at 2.
3 *Id*.
4 *Id*. at 3.
5 PD at 8-11.
6 *Id*. at 9.
7 *Id*. at 10-11.
8 *Id*. at 11.
9 *Id*.

Finally, to the extent such forecasting inaccuracies do become apparent once the changes to the Update schedule are implemented, the ALJ in each ERRA proceeding has significant procedural flexibility to address them. The PD recognizes this, noting that in such case the respective ALJ could require the utility to provide more information or a supplemental "update" prior to the October Update.[10]

For all of these reasons, the Commission should adopt the PD's proposal to move the current "November Update" to October.

II. THE PD'S PROPOSED CHANGE TO THE ERRA APPLICATION DATE IS NECESSARY TO ENSURE ADEQUATE REVIEW BY ALL PARTIES

The Joint IOUs argue an "extra two weeks on the front end" (i.e., changing the filing date for ERRA Applications from June 1st to May 15th) are neither necessary nor meaningful, and that the existing schedule (i.e., from June 1st to early November) is "more than sufficient to litigate what are mostly routine and non-controversial non-Update-related aspects of the Joint Utilities' ERRA Forecast proceedings."[11] CalCCA strongly disagrees.

First, the Joint Utilities argue that the application date should not be moved from June 1st to May 15th because the new requirements applicable to PG&E and SCE as central procurement entities are "complex" and their forecast applications "should not be rushed."[12] In addition, an earlier ERRA application may not include final revisions to LSEs' RA procurement needs.[13] But, as the Joint Utilities point out, the difference requested is a "modest" two weeks' move of the application filing.[14] More significantly, the PD emphasizes the role of each ALJ and their procedural authority and ability to require supplemental information should a significant inaccuracy become apparent.

As CalCCA has argued throughout this proceeding, moving the Update by one month (from November 1st to October 1st) will seriously impact the already truncated, pre-Update discovery and analysis process in ERRA proceedings, unless the IOUs' ERRA Application dates are also moved from June 1st to May 15th.[15] CalCCA reiterates the importance to all ratepayers

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[10] *Id*. at 13.
[11] Joint Utilities' Opening Comments at 5-6.
[12] *Id*. at 5.
[13] *Id*.
[14] *Id*.
[15] R.17-06-026, *California Community Choice Association's Comments in Response to Staff's ERRA Timing Proposal* (June 15, 2021) (CalCCA June 15 Comments) at 6; R.17-06-026, *California*

of a thorough examination of each ERRA Application. To mitigate parties' loss of a month of pre-Update litigation, a minor change in the Application due date from June 1st to May 15th is appropriate and necessary.

CalCCA has also previously listed the important policy considerations addressed in recent ERRA proceedings, and the importance of the ERRA procedure and review process to all ratepayers.[16] That review has resulted in the identification of hundreds of millions of dollars' worth of errors and unfair methodologies for calculating PCIA rates. Contrary to the Joint Utilities' assertion, issues raised throughout the ERRA litigation are generally neither "routine" nor "non-controversial."

For these reasons, the Commission should adopt the PD's proposal to move the annual ERRA forecast application filings from June 1st to May 15th.

III. THE ENERGY INDEX MARKET PRICE BENCHMARK SHOULD ONLY BE CHANGED AFTER DETAILED ANALYSIS AND FURTHER REVIEW

The Joint Utilities urge the Commission to act expeditiously to consider the energy index market price benchmark (MPB) component of the PCIA, also called the "Brown Power Index."[17] The Joint Utilities request that the MPB be set based on the PCIA generation supply portfolios that lead to actual CAISO market revenue results rather than on customer load profiles. The Joint Utilities also request that the Commission schedule workshops as early as possible in 2022 so that these issues can be resolved prior to the utilities' 2023 ERRA Forecast filings in spring 2022.

As CalCCA has previously stated, the proposed change in the MPB calculation is not appropriate at this time, as thorough analysis and review of the impact on PCIA rates has not been performed.[18] CalCCA's position remains unchanged. The proposals to revise the method for establishing the Brown Power Index are not a simple change. If these proposals are adopted, the benchmark would no longer even be an "index." The changes would also eliminate transparency into a major PCIA component and thereby increase uncertainty. These changes

Community Choice Association's Comments in Response to E-Mail Ruling Requesting Comments on Market Price Benchmark Issue Date (Sept. 13, 2021) (CalCCA September 13 Comments), at 10.

16 CalCCA June 15 Comments at 8-9; CalCCA September 13 Comments at 11-12.

17 Joint Utilities' Opening Comments at 10.

18 *Id*. at 3.

should not be undertaken without rigorous analysis and stakeholder input. Therefore, CalCCA supports the Commission's decision in the PD to defer this issue for further consideration.

IV. CONCLUSION

CalCCA appreciates the opportunity to submit these comments.

Respectfully submitted,

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Counsel to
California Community Choice Association

January 11, 2022

Submit comment on Energy storage enhancements - straw proposal

Initiative: Energy storage enhancements

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

The California Community Choice Association (CalCCA) appreciates the opportunity to comment on the Energy Storage Enhancements Straw Proposal. In summary:

- CalCCA supports the California Independent System Operator's (CAISO's) proposal to develop a new energy storage resource model and looks forward to additional details in future iterations regarding how transition costs will be established and how market power mitigation will be applied;
- CalCCA generally supports the proposed reliability enhancements and offers a clarification on the ancillary services proposal; and,
- The CAISO's co-located enhancements must allow storage resources to take full advantage of the federal program for investment tax credits (ITC) by allowing ITC-eligible resources to only charge from its on-site renewable.

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

CalCCA supports the CAISO's proposal to develop a new energy storage resource model in which scheduling coordinators bid in terms of incremental state of charge (SOC) as an alternative to the existing non-generator resource (NGR) model that requires bids in terms of incremental energy. This model will allow for the better reflection of storage resource capabilities through separate hourly bids for charging and discharging, master file parameters to reflect upper and lower capacity limits and ramp rates dependent on SOC, and transition times and costs. CalCCA looks forward to additional details in future iteration regarding how transition costs will be calculated and verified by the CAISO and how market power mitigation will be applied to resources using this model.

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

Ancillary Services

The Straw Proposal explains issues have been identified around the feasibility of storage resources to provide ancillary services awarded in the day-ahead market when the resource does not have sufficient SOC in real-time to deliver energy associated with the ancillary service award. The CAISO states that it may potentially propose in the future that all ancillary service awards for storage be accompanied with bids for energy, such that regulation up awards must be accompanied by a bid to charge, and regulation down awards must be accompanied by a bid to discharge. The CAISO should clarify in its proposal that to the extent necessary to satisfy their award, the storage must provide an energy bid with its ancillary service award. For example, if a storage resource with a Pmax of 100 megawatts (MW) receives a 5 MW regulation up award and the resource is operating at 80 MW, then the energy bid to charge is not needed to ensure the resource can deliver on their ancillary service award. On the other hand, if the same resource receives a 200 MW ancillary service award, then the resource would need energy bids from -100MW to 100 MW (*i.e.*, charge and discharge bids) to deliver on its ancillary service award.

Exceptional Dispatch and Compensation to Hold State of Charge

The CAISO proposes new functionality to allow operators to dispatch storage resources to hold a certain SOC. The proposal would also compensate storage resources exceptionally dispatched to hold SOC using the realized prevailing locational marginal price (LMP) compared to the reference interval discharge price to represent the opportunity costs for exceptionally dispatching the resource. This proposal is a reasonable replacement for the minimum SOC requirement sunsetting in 2023, as it will provide operators the ability to instruct resources to hold SOC when they identify a need and compensate storage resources for the opportunity costs of holding that SOC.

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

The CAISO proposes enhancements to the co-located resource model to ensure co-located storage resources eligible for ITC can reflect their availability in the CAISO market. CalCCA appreciates the steps the CAISO has taken in this proposal to improve the current co-located model to consider the ITC. However, the CAISO's proposal must take into account that the ITC program is a federal program and allow storage resources to take full advantage of such program.

The CAISO's proposal would provide functionality to limit dispatch instructions for storage resources so they are no greater than the forecast of the on-site renewable. When the CAISO issues a dispatch instruction for the renewable to curtail, or cuts a renewable self-schedule, the CAISO will not reduce charging instructions to co-located storage resources. This could result in grid charging.

Because of the way the ITC is designed, it is not possible for storage resources to fully reflect their cost of foregone ITC in the market through bids. When grid charging occurs, the ITC credits are fractionally reduced until the fraction of grid charging exceeds 25 percent. At that time, a storage resource would not be eligible for the ITC at all. There is no way to financially represent when a resource is fully ineligible for ITC within a CAISO market bid because the cost far exceeds the bid cap. For this reason, some storage resources are designed to go offline to avoid grid charging when there is not sufficient energy from the onsite renewable to charge the storage. The CAISO must make an exception for ITC resources, so they are allowed to only charge from the renewable. Such resources should not be required to grid charge when the renewable output is below forecast or when the renewable is curtailed either through economically curtailment, exceptional dispatch, or self-schedule cuts.

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

No comments at this time.

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

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

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January 13, 2022

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SUMMARY OF RECOMMENDATIONS

- Proposals to modify the self-showing process exacerbate disincentives and should therefore be rejected;
- The CPE timeline must provide sufficient time for orderly procurement by both CPEs and LSEs;
- System and flexible RA waivers are needed when CPE credits are not finalized in a timely manner;
- Parties provide compelling justification for CPEs to provide additional information regarding procurement activity; and,
- Before removing the levelized fixed cost bidding requirement, the Commission should provide time to further evaluate the impacts of such a change.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

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

California Community Choice Association[1] (CalCCA) submits these reply comments in response to the *Assigned Commissioner's Scoping Memo and Ruling* (Ruling), issued on December 2, 2021, requesting comments on Phase 1 proposals and workshop.

I. PROPOSALS TO MODIFY THE SELF-SHOWING PROCESS EXACERBATE DISINCENTIVES AND SHOULD THEREFORE BE REJECTED

Alliance for Retail Energy Markets (AREM), Pacific Gas and Electric Company (PG&E), and Middle River Power LLC (MRP) each comment on the multiple proposals in the record to modify the process for self-showing. As an initial matter, CalCCA disagrees with PG&E's[2] and MRP's[3] assertion that the California Independent System Operator's (CAISO's) proposed self-showing process is essentially a residual model.

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1 California Community Choice Association represents the interests of 22 community choice electricity providers in California: Apple Valley Choice Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

2 *Opening Comments of Pacific Gas And Electric Company (U 39 E) On Phase 1 Proposals And Workshop Regarding Central Procurement Entity Structure And Process [Public Version – Appendix A Contains Confidential Information]*, Jan. 4, 2022 (PG&E Opening Comments), at 10-12.

3 *Middle River Power LLC Comments On Phase 1 Proposals*, Jan. 4, 2022 (MRP Opening Comments), at 14-16.

The residual model as originally proposed would have had the California Public Utilities Commission (Commission) determine how much of the local requirement was attributable to each load-serving entity (LSE) and to the extent that the LSE provided part or all of that need, the LSE would have their share of central procurement entity (CPE) procurement costs reduced commensurately. In exchange, the LSE would then be responsible for ensuring that resource is shown in each applicable monthly showing and if unavailable would either provide an alternate resource meeting the CAISO local need or incur the CAISO backstop costs.

Based upon a discussion between the CAISO and CalCCA, this is not the mechanism the CAISO is describing. The CAISO proposed that the Commission "assign the local capacity obligation to LSEs that have agreed to self-show resources under the hybrid procurement framework commensurate with the amount of local capacity they have agreed to show."[4] The CAISO is simply proposing that in the event of a CAISO backstop for local Resource Adequacy (RA) where self-shown RA is not available, the CAISO would allocate the costs of such backstop to the self-showing LSE. The CAISO does not recommend any changes to the initial allocation of local requirements including that of a residual model.

AREM's suggestion that the utilities' and CAISO's proposed modifications to the self-showing process diminish concerns related to risks associated with self-showing is misguided.[5] Risks of self-showing are not improved, rather they are made worse by PG&E's or the CAISO's self-showing proposals because the proposals place additional risk on the self-showing entity by assigning the local obligation and associated backstop costs to the self-showing LSEs. These risks are offset only by a payment for Local Capacity Requirements Reduction Compensation

4 *Phase 1 Proposals of the California Independent System Operator Corporation*, Dec. 23, 2021 (CAISO Phase 1 Proposals), at 4.

5 *Comments Of The Alliance For Retail Energy Markets On Phase 1 Proposals To Address Issues Regarding The Central Procurement Entity*, Jan. 4, 2022 (AREM Comments), at 5.

Mechanism (LCR RCM) which is very low, including $0, and a pro-rata reduction in the costs incurred by the CPE. Given the CAISO soft offer cap for Capacity Procurement Mechanism (CPM) at $6.31/kW-month, the offsetting revenues and cost reductions are likely to be insufficient for an LSE to self-provide a resource.

The following incentives and disincentives exist under the current framework and would be exacerbated if local obligations were shifted to self-showing LSEs under a hybrid model:

Inadequate Incentives

- LCR RCM is no higher than $1.78 per kW-month, which is likely too low to incentivize self-showings given CPM soft-offer cap of $6.31/kW-month and system RA prices.
- LCR RCM is not available to thermal resources and pre-LCR RCM resources, meaning many resources LSEs self-show would not be eligible for any compensation at all.

Disincentives

- Self-shown resources' system and flexible RA value is spread across all LSEs in a constrained market where LSEs may need those resources to meet their system obligations.
- CPE contracts for self-showing in many cases do not allow substitution of a self-shown resource, leaving the self-showing LSE responsible for the full backstop costs when they do not receive the full RA benefit the resource provides.
    - Even if the CPE did allow for substitution of self-shown resources, there is no incentive for the LSE to procure local substitute capacity since it is only self-realizing the system and flexible RA value of the resource and as such, system and flexible obligations represent their substitution risk.
- If substitution is allowed, as proposed in Southern California Edison Company's (SCE's) proposal, LSEs self-showing could mitigate risks of resource unavailability by holding onto other resources for substitution rather than using them for self-showing or their own RA obligations.

LSEs must consider these incentives and disincentives to evaluate the risks associated with self-showing. When the risks of self-showing outweigh the benefit an LSE receives by self-showing, the result will be fewer resources shown to the CPE. Additionally, when many local areas are extremely tight, such that most or all local resources are needed to meet the local RA requirement, it may be impossible for the CAISO to backstop to fill deficiencies. This is because all local resources not shown by the CPE are likely already under contract and being used by other LSEs to meet their system obligations or provide substitution. For these reasons, the Commission should not adopt modifications that would create further disincentives for LSEs to self-show.

II. THE CPE TIMELINE MUST PROVIDE SUFFICIENT TIME FOR ORDERLY PROCUREMENT FOR BOTH CPES AND LSES

CalCCA's proposal to modify the CPE timeline would extend CPE procurement (either through all-source solicitation or bi-lateral contracting) to the end of June 2022 for the 2023 RA compliance year given the significant open position left unprocured for 2023. In future years, the Commission must ensure CPEs complete their procurement activity at least a year in advance as originally contemplated to allow LSEs to adequately plan and conduct their own procurement.

PG&E proposed a CPE showings deadline of mid-August with a stated goal of striking a reasonable balance between clarifying activities and moving up the CPE timeline.[6] However, this proposal does not strike a reasonable balance when it comes to time allotted for CPE procurement and LSE procurement. Giving LSEs two and a half months to conduct their system and flexible RA procurement after CPEs have three years to conduct their procurement is not balanced and should not be adopted. Instead, the Commission should adopt CalCCA's proposed timeline to allow CPEs to conduct additional procurement through June 2022 for RA compliance year 2023, and for future compliance years, direct CPEs to conclude procurement at least one year prior to the start of the RA compliance year to allow adequate time for LSEs to conduct their procurement.

SCE states that its CPE largely met its procurement for 2023 and believes the small residual amount it did not procure can be met in the next annual all-source solicitation.[7] If this

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[6] PG&E Opening Comments at 3-4.

[7] *Opening Comments of Southern California Edison Company (U 338-E) on Phase 1 Proposals and Workshop*, Jan. 4, 2022 (SCE Opening Comments), at 6.

procurement is done in the next annual solicitation, LSEs will not be aware of this procurement and their associated credits until late October 2022 for 2023. This timeline is unacceptably late. While CalCCA understands SCE's open position is small for 2023, the Commission should not establish a precedent that credits for CPE procurement be finalized in October for the next compliance year. Instead, SCE should attempt to fill its open position by June 2022 outside of an all-source solicitation, as supported by SCE in its Phase 1 Proposals[8] and supported by CalCCA in Opening Comments.[9]

Finally, in response to comments from AREM[10] regarding CalCCA's proposed timeline in which final CAM credits are issued to LSEs in late September, CalCCA clarifies here that its proposal would not leave CPE credits to be allocated until late September. Rather, credits related to CPE procurement would be allocated in July 2022 following the completion of CPE procurement and adoption of RA requirements. Only modifications to Cost Allocation Mechanism (CAM) credits based on changes to coincident peak load shares would be left until the late September timeframe.

III. SYSTEM AND FLEXIBLE RA WAIVERS ARE NEEDED WHEN SYSTEM AND FLEXIBLE CPE CREDITS ARE NOT FINALIZED IN A TIMELY MANNER

CalCCA proposed a penalty waiver for system and flexible RA shortfalls caused by the CPE's failure to finalize its portfolio by June 2022 for RA year 2023. The Public Advocates Office (Cal Advocates) does not support a system RA waiver option and suggests if the CPE timeline is modified to allow for earlier certainty of the amounts of CPE credits LSEs will receive, a waiver would not be necessary as the problem of uncertainty would decrease. Cal

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8 *Phase 1 Proposals of Southern California Edison Company (U 338-E)*, Dec.13, 2021, at 8-9.

9 *California Community Choice Association's Comments on Assigned Commissioner's Scoping Memo and Ruling*, Jan. 4, 2022 (CalCCA Opening Comments), at 11.

10 AREM Comments at 2.

Advocates further recommends that if the Commission decides to adopt a waiver process, it should consider a onetime waiver if the CPE timeline is not modified.[11]

CalCCA agrees that if the timeline provides enough certainty in advance of CPE credit volumes, a system waiver would not need to be approved on the basis of CPE credit volume uncertainty. However, for RA year 2023, CPE credit volumes are still unknown and are significantly below the expected amount given the local requirement. Therefore, a waiver is necessary for the 2023 RA year if CPE procurement is not complete and credits allocated by June 2022. If for future RA years, CPE credits are known more than one year in advance as originally contemplated and there is not a significant change in local RA requirements year to year, CalCCA agrees with Cal Advocates that a system RA waiver would not be needed on the basis of CPE credit volume uncertainty.

IV. PARTIES PROVIDE COMPELLING JUSTIFICATION FOR CPES TO PROVIDE ADDITIONAL PROCUREMENT ACTIVITY INFORMATION

CalCCA[12], MRP[13], and WPTF[14] each propose the CPEs provide additional information around CPE procurement activities that would help parties better understand the source of the challenges faced by CPEs under the existing framework and provide informed proposals. PG&E asks the Commission reject these, citing concerns around confidentiality, negative impacts to the CPE process in a constrained local RA market, and necessity of the information requested.[15] Confidentiality protections for market participants are crucial. However, each party proposes

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[11] *Comments of the Public Advocates Office on Phase 1 Proposals*, Jan. 4, 2022, at 6.

[12] *California Community Choice Association's Phase 1 Proposals in Response to the Assigned Commissioner's Scoping Memo and Ruling*, Dec. 13, 2021 (CalCCA Phase 1 Proposals), at 4-5.

[13] *Middle River Power LLC Phase 1 Proposals*, Dec. 23, 2021, at 6-7.

[14] *Western Power Trading Forum Phase 1 Proposals*, Dec. 23, 2021.

[15] PG&E Opening Comments at 14-16.

information that could be easily aggregated to protect the confidentiality of market participants. Further, none of the information proposed by parties would reveal information on prices.

In response to PG&E's suggestion that CalCCA did not explain why its proposal for additional information is required to understand how the CPE structure is functioning,[16] these reply comments reiterate CalCCA's position in Opening Comments regarding why additional information is needed. CalCCA's Opening Comments state additional information is required because without such information, "…it is impossible for parties to know and understand the source of the challenges with procurement in order to develop specific proposals," and "As a result of the CPE uncertainty, LSEs face immediate and significant challenges in securing their own system RA positions."[17] For these reasons, the Commission should adopt parties' proposals for additional information regarding CPE procurement activity.

V. BEFORE REMOVING THE LEVELIZED FIXED COST BIDDING REQUIREMENT, THE COMMISSION SHOULD PROVIDE TIME TO FURTHER EVALUATE THE IMPACTS OF SUCH A CHANGE

SCE proposes the Commission remove the requirement the utilities bid their resources in at their levelized fixed costs and suggests in its Opening Comments that if the Commission feels the investor-owned utilities (IOUs) have a competitive advantage over other LSEs, the IOUs should be able to bid in a monthly shaped price to allow bids to be more competitive with offers from other LSEs.[18] To the extent the levelized fixed cost bidding requirement is inhibiting bids the IOUs otherwise would have submitted to the CPE, considerations should be made to ensure IOUs fully bid their available resources to the CPE. However, in order to fully evaluate the impacts of removing the levelized fixed cost bidding requirement, the Commission should take

16 PG&E Opening Comments at 15.
17 CalCCA Phase 1 Proposals at 4-5.
18 SCE Opening Comments at 8.

additional time before modifying the levelized fixed cost bidding requirement. Such impacts include the flow of costs between Power Charge Indifference Adjustment and CAM and impacts to the RA market. Rather than adopting SCE's proposal in this phase, the Commission should reconsider it in Phase Two, when parties have additional time to consider the impacts of the proposal.

VI. CONCLUSION

For all the foregoing reasons, CalCCA respectfully requests consideration of these reply comments.

Respectfully submitted,

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January 13, 2022

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

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

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
COMMENTS ON THE PROPOSED DECISION
ADOPTING 2021 PREFERRED SYSTEM PLAN**

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SUMMARY OF RECOMMENDATIONS

- ✓ The California Public Utilities Commission (Commission) should commit to ensuring cost effectiveness of planned resources prior to issuing any procurement orders;
- ✓ The "expectation" that resources identified by the Preferred System Plan (PSP) be developed should be removed from the Proposed Decision;
- ✓ Timing for long-lead-time (LLT) resources should be consistent with the Mid-term Reliability (MTR) Decision to ensure accurate California Independent System Operator (CAISO) Transmission Planning Process (TPP) analysis of required transmission capacity;
- ✓ LSEs should be allowed six months from the date the Commission provides the final planning assumptions and inputs to file their Integrated Resource Plan (IRP) plans;
- ✓ Any proposed IRP long-term programmatic structure should not incorporate penalties or backstop procurement;
- ✓ Flexibility to address cost and feasibility considerations for offshore wind as a resource candidate should be incorporated into IRP; and
- ✓ The Proposed Decision should be clarified to explain why proposed procurement in the PSP Core Portfolio decreases as electric vehicle (EV) load increases.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION ADOPTING 2021 PREFERRED SYSTEM PLAN

The California Community Choice Association (CalCCA)[1] submit these comments pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure on the proposed *Decision Adopting 2021 Preferred System Plan* (Proposed Decision or PD) issued on December 22, 2021.

I. INTRODUCTION AND SUMMARY

The significant electric system reliability events in California over the last several years, as well as the effects of global warning and the goals of carbon reduction, have directed intense focus on procurement of additional clean resources. In the race to ensure reliability, as well as the attainment of clean energy targets, one of the "pillars" of Integrated Resource Planning (IRP) has taken a back seat. As noted in the PD, the three goals of IRP include "reliability, [greenhouse gas (GHG)] reductions, and least-cost procurement."[2] Except for one Table in the PD,[3] cost-effectiveness is rarely considered or discussed. In fact, the proposed Preferred System Plan (PSP) Core Portfolio was developed with a permanent planning reserve margin (PRM) of 22.5 percent

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1 California Community Choice Association represents the interests of 22 community choice electricity providers in California: Apple Valley Choice Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

2 PD at 4.

3 *Id.* at 90, Table 3 (incorporating "Scenario Cost Metrics" of various portfolios under consideration for the PSP Portfolio).

through 2032,[4] resulting in a loss of load event (LOLE) expectation of approximately one event every 2000 years. The 22.5 percent PRM is well above industry standard, and the planned LOLE requires capacity that would potentially result in a significant overbuild at customer expense.

Community choice aggregators (CCAs) have stepped up to answer the call for reliability and climate goals, planning for high amounts of GHG-free resources, and including in their IRP plans a diversity of resources planned to meet GHG targets greater than both investor-owned utilities (IOUs) or electric service providers (ESPs).[5] CCAs are also greatly concerned, however, with ensuring that the planned resources are cost-effective. Therefore, the PSP Core Portfolio proposed in the PD is concerning given the substantial overbuild that it will likely require. While reliability and clean energy procurement are appropriate goals, the Commission should continue to focus on *all three* of the IRP goals and commit to reincorporating cost-effectiveness into IRP planning.

CalCCA makes the following recommendations to the Commission in connection with its support of the proposed PSP:

- ✓ The Commission should commit to ensuring cost-effectiveness of planned resources prior to issuing any procurement orders;
- ✓ The "expectation" that resources identified by the PSP be developed should be deleted from the PD;
- ✓ Timing for long-lead-time (LLT) resources should be consistent with the Mid-term Reliability (MTR) Decision to ensure accurate California Independent System Operator (CAISO) Transmission Planning Process (TPP) analysis of required transmission capacity;
- ✓ LSEs should be allowed six months from the date the Commission provides the final planning assumptions and inputs to file their IRP plans;

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4 While the IRP Mid-Term Reliability Decision did include a 22.5 percent PRM through 2026 as its "high need" scenario to ensure reliability, no analysis has indicated the need for the 22.5 percent PRM to persist past 2026. *See* D.21-06-035, *Decision Requiring Procurement to Address Mid-Term Reliability (2023-2026),* R.20-05-003 (June 24, 2021) (MTR Decision), at 20 (adopting the 22.5 percent "high need scenario through 2026).

5 *Administrative Law Judge's Ruling Seeking Comments on Proposed Preferred System Plan,* R.20-05-003 (Aug. 17, 2021), at 8 ("[t]he diversity of resources planned to meet both the 46 MMT and 38 MMT targets is greater in the plans of the [CCAs] than for [IOUs] or [ESPs]. CCAs are also tending to plan for higher amounts of GHG-free resources, including renewables"); *see also California Community Choice Association's Comments on Administrative Law Judge's Ruling Seeking Comments on Proposed Preferred System Plan,* R.20-05-03 (Sept. 27, 2021) (CalCCA Comments on Proposed PSP) at 4, Table 1 (listing nine CCAs with planned GHG targets between 17-34 MMT).

- ✓ Any proposed IRP long-term programmatic structure should not incorporate penalties or backstop procurement;
- ✓ Flexibility to address cost and feasibility considerations for offshore wind as a resource candidate should be incorporated into IRP; and
- ✓ The PD should be clarified to explain why proposed procurement in the PSP Core Portfolio decreases as electric vehicle (EV) load increases.

II. THE COMMISSION SHOULD COMMIT TO ENSURING COST EFFECTIVENESS OF PLANNED RESOURCES PRIOR TO ISSUING ANY PROCUREMENT ORDERS

By focusing on the need for reliability and attainment of clean energy goals, the Commission has deemphasized one of the crucial components of IRP analysis and planning – cost effectiveness. While CalCCA supports adopting the proposed PSP, the Commission should commit to additional cost-effectiveness analysis prior to issuing any procurement orders. Specifically, CalCCA recommends that the Commission: (1) recognize its legislative mandate in California Public Utilities Code sections 454.41 and 454.52 to ensure cost-effectiveness in IRP in addition to reliability and renewable energy procurement; (2) conduct an LOLE study to determine the appropriate PRM past 2026; and (3) incorporate the metrics being developed in the Affordability proceeding (Rulemaking (R.) 18-07-006) to ensure the affordability of any compliance obligations for LSE customers.

A. Public Utilities Code Sections 454.51 and 454.52 Require the Commission to Consider Reliability, Clean Energy and Cost-Effectiveness in IRP

The significant electric system reliability events in California over the last several years, as well as the effects of global warning and the goals of carbon reduction, have directed intense focus on procurement of additional clean resources. CCAs have responded to that focus by planning to build large amounts of GHG-free resources that are more diverse than in the portfolios of the IOUs and ESPs.[6] With the development of this PSP Core Portfolio with a high long term planning reserve margin (22.5 percent), resulting in a LOLE of approximately 1 outage event every 2000 years, however, the Commission has deemphasized one of the crucial components of IRP analysis – cost effectiveness.

Public Utilities Code Sections 454.51 requires the Commission to "identify a diverse and balanced portfolio of resources needed to ensure a reliable electricity supply that provides

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[6] *Id.*

optimal integration of renewable energy in a *cost-effective manner*."[7] The IRP process ensures that LSEs, among other priorities, *"[m]inimize impacts on ratepayers' bills*" through their planned resources.[8] In furtherance of the IRP goals of reliability, GHG reductions and cost effectiveness, the Commission is charged with "reducing the need for electricity generation resources and new transmission resources *in achieving the state's energy goals at the least cost to ratepayers.*"[9]

The PSP Core Portfolio, as proposed in the PD, is based on inputs and assumptions that unnecessarily prioritize reliability over cost effectiveness, when in actuality *both* reliability and cost effectiveness can be achieved. The reasons listed in the PD for adopting the PSP portfolio (accurate representation of IRP plans, based on demand forecast, meets aggressive GHG target, and modeled to be reliable) notably omit any consideration of costs or affordability implications for customers.[10] The PSP core portfolio is intended as a planning tool and does not in itself create procurement mandates, but the elimination of the Reference System Plan (RSP) elevates the PSP's importance and precedent for the next IRP cycle. In addition, the PSP core portfolio will be utilized by the CAISO to plan for transmission upgrades through the TPP. Therefore, careful consideration of reliability, GHG targets, *and* costs is crucial for the PSP process.

B. The 22.5 Percent Planning Reserve Margin Has Not Been Adequately Justified and Could Result in an Overbuilt System

LOLE results from the PSP suggest that the PRM could be lowered while still meeting reliability criteria, therefore creating a more cost-effective electric system. The revised PSP Core Portfolio as set forth in the PD results in an LOLE of 0.0023 in 2026, 0.0005 in 2030, and 0.0006 in 2032.[11] These resulting LOLE values are significantly lower than the proposed PSP set forth in the ALJ Ruling, which Table 4 lists as 0.064 in 2026, and 0.054 in 2030.[12]

The Commission has recognized the need for, but has not developed, a consistent approach with respect to the PRM. In the MTR Decision, the Commission refrained from "setting new standards for PRM, LOLE, or weather variants of the demand forecast," instead

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7 Cal. Pub. Util. Code § 454.51(a) (emphasis added).

8 *Id.* § 454.52(a)(1)(D) (emphasis added).

9 *Id.* § 454.52(a)(3) (emphasis added).

10 *See* PD at 105-106.

11 *Id.* at 102, Table 6.

12 *Id.* at 93, Table 4.

stating that it will "continue additional analysis and stakeholder engagement before making major changes."[13] The MTR Decision stated that:

> Should the Commission decide to continue to use an LOLE metric of 0.1, we agree that the PRM should be set at a level that accomplishes this reliability level, and the analysis should be regularly updated. Commission staff is currently conducting such an analysis, and additional analysis and discussion of these issues will be forthcoming in this proceeding. In the meantime, we will not make revisions to the long-term assumptions in this proceeding.[14]

A 20.7 percent PRM was found to be a "reasonable proxy" for the mid-term reliability requirements (*i.e.*, 2023-2026), although greater than the 17.5 percent PRM used in the 2021 emergency reliability proceeding.[15] The Commission found that with the longer timeframe being considered, accounting for "some contingency, as well as both the reliability and environmental goals that drive the need for greater investment of new and improvement of existing resources," is necessary.[16] Additionally, after a long discussion of the reliability challenges and climate change concerns, the Commission adopted the "high need" scenario PRM of 22.5 percent for the mid-term needs through 2026.[17]

The Commission then (without explanation) extended the 22.5 percent PRM past 2026 in the proposed PSP Core Portfolio and did not conduct an LOLE analysis on a "non-persistence" sensitivity. As CalCCA noted in its comments on the proposed PSP core portfolio, such a sensitivity "is important to the 38 million metric ton (MMT) Core [which was being recommended by the Commission at that time] and is consistent with previously established IRP planning assumptions."[18] Given the lack of LOLE analysis to demonstrate the necessity of keeping the 22.5 percent PRM past 2026, and the 2030 LOLE results of substantially below the 0.1 LOLE standard (at 0.054 LOLE), CalCCA warned of the potential for an overbuilt system.[19] CalCCA recommended re-running the Renewable Energy Solutions Model (RESOLVE) with a 17.5 percent PRM for the years 2026-2030, and then testing the portfolio output in the Strategic

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13 MTR Decision at 11.
14 *Id.* at 12.
15 *Id.*
16 *Id.*
17 *Id.* at 14, 20.
18 CalCCA Comments on Proposed PSP at 5.
19 *Id.*

Energy & Risk Valuation Model (SERVM) to see if the 17.5 percent PRM would result in a reliable portfolio.[20]

While the Commission recognized CalCCA's request to re-run the "non-persistence" sensitivity in the PD, it failed to do so, instead stating that:

> As far as persistence of the PRM assumptions, it may be that a new paradigm needs to be developed and adopted for reliability purposes going forward. However, until the conclusion of such an effort, we find it prudent to continue to include *conservative* assumptions for reliability in the TPP portfolios now, since they have recently proven to be important for maintaining reliability in the very near term.[21]

What the Commission fails to mention, however, is that the tradeoff for the intense focus on only reliability and the use of overly conservative assumptions could potentially result in an overbuilt system with excess capacity at the expense of customers. Therefore, while CalCCA accepts the PSP proposed in the PD for this IRP cycle, such a study should be conducted prior to any future procurement orders. CalCCA continues to strongly encourage the Commission to conduct a study to establish a new PRM for both the IRP and RA proceedings.[22]

C. Affordability Considerations Should be Incorporated into the IRP Process

The PD "commits to further evolving the Commission's IRP process by developing a programmatic approach to IRP procurement."[23] This stakeholder process, expected to be conducted in 2022, will be conducted "likely in coordination with the resource adequacy (RA) and renewable portfolio standard (RPS) programs"[24] to better align these programs, as has been discussed many times in this IRP proceeding. Notably absent, however, is any consideration of the Commission's Affordability proceeding (R.18-07-006), or a plan to incorporate the recommendations set forth in the Commission's recent publication on ensuring affordability

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[20] *Id.*

[21] PD at 109 (emphasis added).

[22] In addition to additional LOLE study, the addition of "real world observations" to simulate storage in the SERVM analysis for the PSP, which was added at the eleventh hour after stakeholders had already analyzed and commented on the PSP modeling, is concerning. *See id.* at 101-102. While CalCCA does not necessarily disagree with the addition of such analysis, this substantial alteration to the SERVM analysis, without modeling such constraints in RESOLVE, raises additional concerns with the recommended PRM and portfolio and any potential associated requirements on LSEs.

[23] *Id.* at 151.

[24] *Id.*

while building the "grid of the future."[25] The CPUC Affordability Report recognizes the significant impact of transportation electrification goals on affordability, as well as capital investments . . . necessary to meet California's energy and climate policy goals," both of which "can result in higher bills for customers."[26] In addition, parties in the Affordability proceeding are currently considering the use of affordability metrics to inform decisions on revenue requirement proposals.[27] While IOU revenue requirements will surely include increased procurement costs as a result of an overbuilt system, CalCCA has proposed in Comments in the Affordability proceeding that the affordability metrics be applied in proceedings such as IRP that could potentially raise LSE costs of compliance and therefore customer bills.[28] The Commission should therefore be incorporating not only RA and RPS alignment into the IRP process, but should also incorporate the principles being developed in the Affordability proceeding "to assess affordability impacts of utility investments and Commission programs."[29]

III. THE "EXPECTATION" THAT RESOURCES IDENTIFIED BY THE PSP MUST BE DEVELOPED BY LSES SHOULD BE DELETED FROM THE PD

The PD states that "[a]ny resources associated with the PSP, or resource attributes thereof, will be *expected to be developed* by the LSEs."[30] The PD must be revised to remove this statement for several reasons. As set forth above, the PSP Core Portfolio is intended to be a planning tool, and not a procurement mandate. In fact, PSP portfolios developed in the IRP proceeding to date have varied dramatically across cycles. The 2018 PSP selected approximately 12 gigawatts (GW) of new capacity by 2030.[31] The current PSP selects nearly three times that

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25 *See Utility Costs and Affordability of the Grid of the Future: An Evaluation of Electric Costs, Rates, and Equity Issues Pursuant to P.U. Code Section 913.1* (May 2021) (CPUC Affordability Report), located at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/office-of-governmental-affairs-division/reports/2021/senate-bill-695-report-2021-and-en-banc-whitepaper_final_04302021.pdf

26 *Id.* at 3. The CPUC Affordability Report also lists wildfire mitigation as a significant cost that will impact rates.

27 *See Assigned Commissioner's and Assigned Administrative Law Judge's Ruling Inviting Comments on Staff Proposal on Implementation of Affordability Metrics*, R.18-07-006 (Nov. 5, 2021) (ALJ Ruling) at 26 (requesting comment on the *Affordability Metrics Implementation Staff Proposal,* R.18-07-006 (Nov. 5, 2021)).

28 *See California Community Choice Association's Comments on Assigned Commissioner's and Assigned Administrative Law Judge's Ruling Inviting Comments on Staff Proposal on Implementation of Affordability Metrics,* R.18-07-006 (Jan. 10, 2022), at 4-5.

29 *Order Instituting Rulemaking to Develop Methods to Assess the Affordability Impacts of Utility Rate Requests and Commission Proceedings,* R.18-07-006 (July 12, 2018), at 9.

30 PD at 95.

31 *See* D.19-04-040, *Decision Adopting Preferred System Portfolio and Plan for 2017-2018 Integrated Resource Plan Cycle,* R.16-02-007 (April 25, 2019), at 114.

amount. This dramatic change in two years points to the difficulty in being held to any one long term system plan.

Second, the modeling tools used in the IRP process may not reflect existing or future policy goals and criteria. Of note, the RESOLVE model selected 926 megawatts (MW) of new gas resources in 2045 to meet the 22.5 percent PRM.[32] This selection by the model runs counter to the state's climate goals. While 2045 results are outside the planning horizon of the IRP, such results point to the problem with overreliance on modeling results and holding LSEs accountable for development of resource forecasts ten or more years into the future.

In addition, for many resources, LSEs alone cannot ensure certain resources are built. For example, out of state and offshore wind development will require the support of state and federal agencies to ensure transmission and permitting is complete.

Furthermore, the relationship between the PSP and any subsequent LSE procurement is subject to further development in the next IRP cycle as scoped in this PD. Therefore, this statement appears to prejudice the outcome of the programmatic design process before stakeholders have had an adequate opportunity to assist the Commission in developing a new programmatic approach.

For these reasons, the PD should be revised to remove any "expectation" of procurement by LSEs in connection with the PSP. Instead, the current process in which the Commission monitors progress toward resource development and the need for resources is updated in each IRP cycle is sufficient.

IV. THE PSP SHOULD BE MODIFIED TO ENABLE ACCURATE CAISO TPP ANALYSIS OF REQUIRED TRANSMISSION CAPACITY FOR LONG-LEAD-TIME RESOURCES

The PD should be modified to ensure that the PSP Core Portfolio accurately represents the MTR requirements for LLT resources for the purposes of transmission planning. The PSP Core Portfolio currently pushes LLT resources to 2028, presumably to ensure portfolio reliability given the risk of project delays. While it is reasonable to test this outcome as a sensitivity, it is critical to use consistent planning assumptions across both the IRP and TPP. As a result, these LLT resources should be included in the transmission planning portfolio with the mandated 2026

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32 PD at 101.

online date reflected in the MTR. This will enable the CAISO to begin the necessary analysis and evaluation to provide transmission capacity for these resources.

A. Accurate Timing for Geothermal Long-Lead-Time Resources Must Be Considered in Transmission Planning Due to Likely Import Capability Expansion Needs

The issues of accurately reflecting MTR LLT online requirements for the TPP is particularly acute for import geothermal resources that will be required to fulfill the clean firm component of the LLT mandate. Table 14 of the busbar mapping of the PSP Core Portfolio shows 88 percent of geothermal capacity (1.02 gigawatts (GW) of 1.16 GW) being developed outside CAISO.[33] These resources will require the CAISO to evaluate the potential need for expanding import capability and will likely require transmission upgrades outside the state — both potentially lengthy processes. Delaying their representation in the portfolio unnecessarily increases the risk that candidate resources do not achieve deliverability in the timeframe outlined in the MTR Decision. To alleviate this risk, the Commission should request that the CAISO provide specific information on potential increases to Maximum Import Capability ("MIC") at different delivery points for import LLT resources. Many delivery points are currently constrained and without an understanding of the potential for import capability expansion, contracting with resources outside of the CAISO is unnecessarily risky.

B. The Commission's Busbar Mapping Must Accurately Reflect the Availability and Location of Cost-Effective Geothermal Resources

The magnitude and geographic representation of resources reflected in the Core Portfolio that are expected to fulfill the clean firm LLT requirements are not likely aligned with the market. While details on ongoing solicitations are confidential, CCAs report that responses to both joint and individual procurement efforts reveal potential quantity shortfalls and a lack of geographic congruence with Commission assumptions. This should not be a huge surprise since many of the qualifying resources are location-constrained and located either outside of California or, at a minimum, outside of the CAISO Balancing Authority Area (BAA). CalCCA is concerned that the busbar mapping in the Core Portfolio does not accurately reflect the availability and location of the resources to meet the LLT requirements. GridLiance identified this disconnect in their opening comments on the PSP, noting that Nevada geothermal was unnecessarily constrained by an outdated legacy limit to the total potential and a misrepresented transmission

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[33] PD, Attachment A, *Modeling Assumptions for the 2022-2023 Transmission Planning Process: CPUC Staff Report* (Dec. 2021), at 46 (Table 14).

expansion option.[34] Failing to accurately reflect the location of cost-effective resources will likely prevent the CAISO from evaluating the necessary import expansion or transmission upgrades for fulfilling the LLT requirements.

CalCCA suggests updating the PSP Core Portfolio to reflect this likelihood. In the alternative, the CPUC should request the CAISO test a scenario with at least the majority of new geothermal resources sited in Nevada, outside of the CAISO BAA. This is a critical issue to resolve to prevent a mismatch between the preferred portfolio in terms of size and location versus what the market is able to offer online by 2026 and which may be available for LSEs to procure.

V. THE MODIFIED IRP CYCLE PROCESS SHOULD ALLOW ADEQUATE TIME FOR LSES TO PREPARE THEIR IRP PLANS

CalCCA appreciates the Commission's consideration of refinements to the IRP cycle process and schedule.[35] Given experience with the development and submission of LSE plans in 2020, CalCCA recommends building into the process more time for LSEs to develop their IRP Plans after receiving the final planning standards and templates from the Commission. CalCCA recommends modifying the PD to: (1) require the planning inputs and assumptions to be provided by the Commission earlier than May 1st, and (2) provide LSEs six months (180 days), rather than four months, to develop their LSE plans after receiving final planning inputs and assumptions from the Commission.

A. The 2020 LSE IRP Submission Process Provided Inadequate Time for LSEs to Develop Their Plans After Receiving Final Planning Inputs and Assumptions from the Commission

During the 2020 process, LSEs did not receive *final* planning inputs and assumptions until June 15, 2020 (with final guidance on August 11 through an update to the Filing Requirements), with the LSE plans due on September 1. Given the extremely short timeframe with which LSEs had to prepare their plans, which includes substantial modeling runs and analysis, extensive follow-up was required by the Commission following the submission of plans. If given final planning inputs and assumptions, and templates, with adequate time for model development and analysis, LSEs could develop complete plans with greater cost

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[34] *See GridLiance West LLC Comments on Administrative Law Judge's Ruling Seeking Comments on Proposed Preferred System Plan,* R. 20-05-003 (Sept. 27, 2021).

[35] PD at 65-71.

efficiency (i.e., reduced reruns of modeling and dedication of resources to refining plans). Additional time for LSE planning is even more critical given the Commission's requirement set forth in the PD that LSEs will now have to include two additional years of planning information (from ten years to 12 years to accommodate TPP analysis).[36]

B. The PD Should Be Modified to Require Planning Standards to be Provided Earlier, and Allow LSEs at Least 180 Days After Receiving Final Planning Standards to Submit IRP Plans

The PD states that "Commission staff will *aim* to have [the planning standards and templates] available [to LSEs] no later than May 1, 2022."[37] However, "[i]ndividual LSE plans will be due no later than September 1, 2022."[38] As a result, LSEs will only have four months (assuming the information provided in May is in final form and not subject to change) to conduct the modeling and analysis, as well as LSE stakeholder processes which in the case of CCAs includes submitting plans to their Boards for approval after lengthy stakeholder input.[39] As the Proposed Decision notes, CalCCA has previously recommended nine months as a required time frame to conduct all necessary modeling, narrative development, stakeholder input, and data template completion, based on the experiences in the last cycle of IRP, so even a six-month time frame is greatly accelerated.[40] With the elimination of the requirement that the Commission develop a RSP, additional resources should be allocated to develop the planning targets for the Clean System Power (CSP) tool and planning direction for LSEs, as well as the final LSE filing templates, sooner than they were provided in the 2020 cycle.

CalCCA recommends that LSEs be provided with the final planning inputs, assumptions, and templates earlier than May 1. Second, LSEs should be allowed six months (180 days) *after* receiving the final planning inputs, assumptions, and templates to submit their plans. At least 180 days is necessary for LSEs to develop their plans after receiving the planning inputs, assumptions and templates.

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36 *Id.* at 71.

37 *Id.* at 70 (emphasis added).

38 *Id.*

39 Cal. Pub. Util. Code § 454.52(b)(3) ("[t]he plan of a [CCA] shall be submitted to its governing board for approval and provided to the commission for certification, . . .").

40 PD at 78.

VI. ANY PROPOSED IRP LONG-TERM PROGRAMMATIC STRUCTURE SHOULD NOT INCORPORATE PENALTIES OR BACKSTOP PROCUREMENT

CalCCA is appreciative of the Commission's commitment in the PD to increase predictability regarding procurement obligations through the development of a programmatic structure for procurement.[41] CalCCA encourages the Commission to avoid incorporating aspects of past emergency short-term procurement orders, such as backstop procurement and penalties, into any long-term IRP structure. With adequate planning, any backstop procurement and/or penalties for non-procurement should be unnecessary and would be inappropriate as a programmatic feature of IRP. Public Utilities Code sections 454.51 and 454.52, establishing the IRP structure, does not incorporate any such backstop procurement or penalties, nor should it. Going forward as the Commission develops the IRP program, the focus should remain on the legislative requirements for IRP – developing a "diverse and balanced portfolio of resources needed to ensure a reliable electricity supply that provides optimal integration of renewable energy in a cost-effective manner."[42] CalCCA looks forward to participating in the development of an approach to evolve the Commission's IRP process.

VII. FLEXIBILITY TO ADDRESS COST AND FEASIBILITY CONSIDERATIONS FOR OFFSHORE WIND AS A RESOURCE CANDIDATE SHOULD BE INCORPORATED INTO IRP

CalCCA supports the exploration of offshore wind development on the west coast and its inclusion in the PSP. However, the Commission should also embrace flexibility to address cost and feasibility of this new technology as 2032 grows closer. The Commission should be prepared with other scenarios that do not rely on offshore wind if unforeseen challenges arise with respect to cost or feasibility. Such an approach is consistent with the IRP's long-term planning focus and allows California to change course if the circumstances warrant it.

VIII. THE PD SHOULD BE CLARIFIED TO EXPLAIN WHY PROPOSED PROCUREMENT IN THE PSP CORE PORTFOLIO DECREASES AS EV LOAD INCREASES

The PD explains that the original analysis included in the August 17, 2021 ALJ Ruling used the CEC's 2019 Integrated Energy Policy Report (IEPR) forecast as an input to RESOLVE

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[41] *Id.* at 149-153.

[42] Cal. Pub. Util. Code § 454.51(a).

for the 38 MMT Core Portfolio.[43] However, the PD now proposes to use the 2020 IEPR with the "High EV penetration assumption instead of the mid EV assumption."[44] The PD includes the resulting RESOLVE buildout from both scenarios. The new results (2020 IEPR with High EV) have 1,829 MWs *less* total new build in 2030 than the previous results (2019 IEPR), including 1,691 less storage MWs.[45] This result is counterintuitive, given that the 2020 IEPR appears to have a *higher* baseline (i.e. before load modifiers) peak load than the 2019 version (by approximately 1,314 MW in 2030),[46] and that changing the EV penetration assumption from "mid" to high" adds approximately 244 MW of peak load relative to the baseline scenario.[47] Therefore, the Commission should clarify why increased peak load leads to less new build.

IX. CONCLUSION

CalCCA appreciates the opportunity to submit these comments. For all the foregoing reasons, the Commission should modify the proposed decision as provided in Attachment A.

Respectfully submitted,

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CALIFORNIA COMMUNITY CHOICE ASSOCIATION

January 14, 2022

43 PD at 84-85.

44 *Id.* at 99.

45 *Id.* at 87, Table 2 (2019 IEPR build), and 100, Table 5 (2020 IEPR and High EV build. Table 2 has 14,086 of storage MW build in 2030, whereas Table 5 has 12,395.

46 See RESOLVE Scenario Tool, Loads Forecast tab, at rows 232-233, available at ftp://ftp.cpuc.ca.gov/energy/modeling/2021%20PSP%20RESOLVE%20Package.zip

47 *Id.* at rows 442-444.

ATTACHMENT A

PROPOSED MODIFICATIONS TO TEXT IN PD, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDERING PARAGRAPHS

MODIFICATIONS TO TEXT OF PD:

- PD at 95:

  ~~Any resources associated with the PSP, or resource attributes thereof, will be expected to be developed by the LSEs. Their procurement will need to match their emissions and reliability responsibilities associated with the PSP by 2030 and in the interim years.~~

- PD AT 168 (Table):

Commission staff dissemination of final ~~proposed~~inputs and assumptions for use in the 2022-23 IRP cycle	No later than May 1, 2022
Final ~~U~~updates to certain LSE filing requirements (*e.g.,* LSE GHG planning targets)	No later than May 1, 2022
Individual LSE IRP filings	~~September 1, 2022~~180 days after Commission staff dissemination of proposed inputs and assumptions for use in the 2022-23 IRP cycle/Updates to certain LSE filing requirements (*e.g.,* LSE GHG planning targets)

FINDINGS OF FACT

No changes

CONCLUSIONS OF LAW

8. Filing requirements for the next set of individual IRP filings should be based on the PSP adopted in this decision, and the analysis conducted to inform it such as the RESOLVE sensitivity portfolios, with the exception of the 22.5 percent planning reserve margin used to develop the PSP. The next set of individual IRP filings in 2022 will be due 180 days after the Commission provides the planning inputs and assumptions for use in the 2022-23 IRP cycle and updates to certain LSE filing requirements (*e.g.,* LSE GHG planning targets).

12. The Commission should recommend to the CAISO that the PSP portfolio adopted in this decision should be its reliability base case and policy-driven base case for its 2022-2023 TPP. The long-lead-time resources required by the D.21-06-035 should be assumed to be online as of 2026 for purposes of the reliability base case.

21. Commission staff should produce an addendum to the busbar mapping of the PSP portfolio if the 2021-2022 TPP outputs identify preferable locations for OOS renewable resources to be mapped. The long-lead-time resources required by the D.21-06-035 should be assumed to be online as of 2026 for purposes of the reliability base case.

22. Federal and State plans for offshore wind development ~~will~~may benefit the electric system and the Commission should include this technology as a candidate resource in capacity expansion modeling as soon as possible if cost-effective and feasible.

23. The Commission should encourage LSEs to pursue viable opportunities for offshore wind projects if cost-effective and feasible.

ORDERING PARAGRAPHS

7. The Commission transmits to the California Independent System Operator (CAISO) for use in its 2022-2023 Transmission Planning Process (TPP) the Preferred System Plan portfolio adopted in Ordering Paragraph 6 above and reflected in Attachment A to this decision, as both the reliability base case and the policy-driven base case. The long-lead-time resources required by D.21-06-035 should be assumed to be online as of 2026 for purposes of the reliability base case. The Commission also delegates to Energy Division staff, in consultation with staff of the California Energy Commission and CAISO, the development of a policy-driven sensitivity portfolio based on a 30 million metric ton greenhouse gas target, and associated busbar mapping, if it is determined by Commission staff to be feasible within the next few months.

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

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION REPLY COMMENTS ON THE PROPOSED DECISION ADOPTING 2021 PREFERRED SYSTEM PLAN

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SUMMARY OF RECOMMENDATIONS

- ✓ The Proposed Decision should be modified to immediately establish a separate proceeding track to establish cost-effective, appropriate reliability planning standards.
- ✓ The Commission should adopt SCE's proposal to delay LSE IRP Filings until the long-term assumptions and standards are established.
- ✓ Busbar mapping should reflect the availability and location of cost-effective resources to fulfill Commission requirements, including geothermal resource opportunities in Nevada.
- ✓ The Commission should schedule a workshop to incorporate stakeholder input in its busbar mapping.
- ✓ The Commission should schedule a workshop to analyze SCE's proposal that CAM'd resources procured pursuant to D.21-12-015 count towards all benefitting LSEs' MTR requirements.
- ✓ The Commission should not establish a central procurement process for offshore wind.

I. INTRODUCTION

The California Community Choice Association (CalCCA) submits these Reply Comments pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure on the proposed *Decision Adopting 2021 Preferred System Plan* (PD or Proposed Decision) issued on December 22, 2021.

II. THE PD SHOULD BE MODIFIED TO IMMEDIATELY ESTABLISH A SEPARATE PROCEEDING TRACK TO ESTABLISH COST-EFFECTIVE, APPROPRIATE RELIABILITY PLANNING STANDARDS

CalCCA recommends in Opening Comments that the Commission commit to studying its reliability planning standards, including the appropriate planning reserve margin (PRM) and resulting loss of load event (LOLE) expectation, to ensure cost-effectiveness and to prevent an overbuilt system.[1] A wide spectrum of stakeholders, including Southern California Edison Company (SCE),[2] Pacific Gas and Electric Company (PG&E),[3] the Alliance for Retail Energy Markets (AReM),[4] Calpine Corporation (Calpine),[5] the City and County of San Francisco (CCSF),[6] the Utility Reform Network (TURN),[7] and the Green Power Institute (GPI), similarly recommend that the Commission commit to refining its planning standards. As set forth below, CalCCA endorses SCE's proposal to delay load serving entities' (LSEs') Integrated Resource Plan (IRP) filings until completion of a planning standards study. CalCCA further recommends avoiding any immediate resource "additions" to the portfolio to account for "uncertainties," as recommended by a small number of parties, that would likely result in an overbuilt system at customer expense.

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1 *CalCCA Opening Comments* at 3-6. Opening Comments of all parties cited will be referred to by party name.

2 *SCE Opening Comments* at 2-4 (emphasizing that the reliability capacity resulting in an LOLE of 0.0005 in 2030 (or 1-in-2000) "comes at a substantial cost to customers" and that the Commission must initiate a process to find "the appropriate balance between reliability and affordability").

3 *PG&E Opening Comments* at 8-9 (noting that "the unsupported 22.5 percent PRM will lead to unnecessarily higher energy rates for California consumers and potentially creates a divergence in the IRP and RA proceedings," and proposing a "potential approach for revising the reliability planning standard in a stakeholder-driven process").

4 *AReM Opening Comments* at 2-4 (stating that "[t]he PD downplays the costly significance of the [22.5 percent PRM and resulting LOLE well under the 0.1 target]," and that at a minimum, future IRP cycles must recognize that this PRM leads to an LOLE far below and more stringent than the 0.1 planning standard and thus does not represent a benchmark for future planning").

5 *Calpine Opening Comments* at 1-2 (the Commission should "remain mindful of cost" and "remove capacity . . . consistent with the 1-in-10 standard or, at a minimum, ensure that any modeling that is used to justify procurement prospectively is consistent with the CPUC's reliability targets").

6 CCSF Opening Comments at 6-7 (noting that the excessively low LOLE results "indicate that the system has more resources than what is needed to maintain reliability," and an LOLE PRM setting analysis should be conducted to provide the final inputs/assumptions to LSEs for the IRP Plan filings).

7 *TURN Opening Comments* at 4 (recommending the use of a PRM in the next IRP cycle "that will not produce an excessively low LOLE result" to remedy "a system that has significantly more capacity than is needed to meet reliability standards").

A. The PD Should be Modified to Adopt SCE's Proposal to Delay LSE IRP Filings Until the Long-Term Planning Standards are Established

As set forth in detail in CalCCA's Opening Comments, the Commission's planning standards have prioritized reliability and climate concerns at the expense of cost-effectiveness. SCE recommends in its Opening Comments that the Commission:

> prioritize the study of system reliability assumptions now by modifying the PD to include a separate track to evaluate and determine the appropriate range of probabilistic planning inputs in the presence of climate change (*i.e.,* demand forecast scenarios, variable generation output scenarios, outage rates, etc.), appropriate LOLE metric targets (e.g., 1-in-10, 1-in-20, 1-in-50, etc.), suitable PRM to be used for IRP resource portfolios, and reasonable methods for evaluating the contribution of various resources to system reliability. This critical work must inform the inputs and assumptions to be used in the 2022-23 IRP cycle; *accordingly, it must occur now, before LSEs develop their next resource plans.*[8]

CalCCA emphasizes in Opening Comments that such a study must occur prior to any new procurement orders. CalCCA also agrees with SCE, however, that establishing appropriate inputs and assumptions prior to LSEs submitting their plans will lead to a Preferred System Plan (PSP) / Transmission Planning Process (TPP) portfolio that appropriately balances the need for reliability, meeting climate goals, *and* affordability for customers. The Commission should adopt SCE's proposal to extend the IRP filing schedule to allow for stakeholder input and Commission analysis and development of robust planning standards in 2022 *prior to* the development of LSE plans. After receipt of the planning standards, LSEs should be given at least 180 days to prepare their IRP Plans.[9]

B. Recommendations by CAISO and CESA to Overbuild the System to Ensure Reliability Demonstrate the Immediate Need for Robust Planning Standards

Given the lack of transparency and consistency in the application of planning standards across Commission orders and proceedings (including the Emergency Summer Reliability and Resource Adequacy proceedings), parties variously request overbuilding the system to account for uncertainties. For example, the California Independent System Operator (CAISO) proposes additional battery storage procurement in the mid-term to account for "procurement, forecast, and operational uncertainties" and to "serve as a buffer against resource delays and the planned 2024 Diablo Canyon Power Plant [DCPP] decommissioning."[10] The Commission, however, already issued the MTR Decision[11] to account for

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8 *SCE Opening Comments* at 2-3 (emphasis added).
9 *CalCCA Opening Comments* at 11.
10 *CAISO Opening Comments* at 5.
11 D.21-06-035, *Decision Requiring Procurement to Address Mid-Term Reliability (2023-2026),* R.20-05-003 (June 24, 2021) (MTR Decision).

DCPP decommissioning, and building in a "buffer" over and above the proposed build is not an appropriate method to ensure an optimal resource portfolio.

In addition, the California Energy Storage Alliance (CESA) proposes that the Commission adopt the PSP and include 2 gigawatts (GW) of incremental storage resources to allow "reasonable hedges against transmission planning and reliability risks."[12] Again, robust and accurate planning standards should prevent the need to tack on additional resources after arriving at a proposed portfolio.

III. BUSBAR MAPPING SHOULD REFLECT THE AVAILABILITY AND LOCATION OF COST-EFFECTIVE RESOURCES TO FULFILL COMMISSION REQUIREMENTS, INCLUDING GEOTHERMAL RESOURCE OPPORTUNITIES IN NEVADA

Of utmost importance to the development of the TPP is current geographic and market information, to allow for significant, cost-effective resource development in line with Commission requirements. GridLiance West LLC (GridLiance), the Nevada Governor's Office of Energy, and the Coalition for the Optimization of Renewable Development (CORD) all concur with CalCCA's Opening Comments that the PSP Core Portfolio should be updated to reflect the availability and location of cost-effective resources (i.e., "long-lead-time resources" that can fulfill the Commission's Mid-term Reliability (MTR) requirements), including geothermal resources, in Nevada.[13] PG&E also points to the need to use updated LSE procurement portfolios to account for location-specific resource requirements and to avoid the risk of stranded transmission investments with transmission upgrades identified by the TPP not reflecting the most current need.[14] The Commission should update the PSP Core Portfolio to allow the CAISO to evaluate necessary import expansion or transmission upgrades. Specifically, the PSP should be updated to plan for at least 2,000 MW of further incremental renewable resources imported from Nevada, which falls within the range of available resources cited by the relevant stakeholders.[15]

IV. COMMISSION STAFF SHOULD HOLD A WORKSHOP TO INCORPORATE STAKEHOLDER INPUT IN ITS BUSBAR MAPPING

GridLiance, SCE, and the Solar Energy Industries Association/Large-Scale Solar Association (Joint Solar Parties) recommend increased stakeholder input on the busbar mapping conducted by

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12 *CESA Opening Comments* at 2-5.

13 *GridLiance Opening Comments* at 3; *see also Nevada Governor's Office of Energy Opening Comments* at 4; *see also CORD Opening Comments* at 3-5.

14 *PG&E Opening Comments* at 7.

15 *See Gridliance Opening Comments at* 5.

Commission Staff.[16] CalCCA agrees that increased stakeholder input would result in more accurate and transparent mapping for the TPP. As such, the Commission should schedule a workshop, as requested by the Joint Solar Parties, to allow stakeholder input on Commission Staff's busbar mapping methodology. Such a workshop should be held in future IRP cycles during the preparation of the PSP, but in this cycle prior to providing the PSP to the CAISO for TPP purposes.

V. THE COMMISSION SHOULD SCHEDULE A WORKSHOP TO ANALYZE SCE'S PROPOSAL THAT CAM'D RESOURCES PROCURED PURSUANT TO D.21-12-015 COUNT TOWARDS ALL BENEFITTING LSES' MTR REQUIREMENTS

SCE proposes that system reliability resources procured pursuant to Decision (D.) 21-12-015,[17] addressing Potential Extreme Weather events in the summers of 2022 and 2023, that continue to provide reliability benefits after 2023 and for which costs are recovered through the Cost Allocation Mechanism (CAM), count towards all paying LSEs' MTR requirements on a pro-rata basis.[18] In other words, the MTR compliance benefit for such resources will be allocated to each LSE pro-rata based on the load forecast used to set the MTR requirements. In general, customers that pay for a CAM-eligible resource should receive the full reliability benefit of the resource by having the resource count towards compliance obligations. SCE's proposal should be further explored through a stakeholder workshop after the IOU's provide information on the resources involved, including the types and amounts of resources eligible for CAM treatment for each LSE. Given community choice aggregators (CCAs) have already begun procurement activities to meet the MTR obligation, it is prudent to hold such a workshop as soon as feasible. In addition, the Commission should allow such resources to count towards any future procurement orders, and should allow an LSE to transact with other jurisdictional LSEs to transfer such resources (*i.e.*, sell their portion of the allocated resource to another LSE to allow LSEs to optimize their procurement efforts) if the resources are duplicative of MTR resources already procured by the LSE. The Commission must limit over-procurement by IOUs of resources that will continue to be allocated through CAM following the emergency procurement timeframe.[19]

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16 *GridLiance Opening Comments* at 5-6; *SCE Opening Comments* at 6-7; *Joint Solar Parties Opening Comments* at 7-9.

17 *Phase 2 Decision Directing Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company to Take Actions to Prepare for Potential Extreme Weather in the Summers of 2022 and 2023,* R.20-11-003 (Dec. 2, 2021).

18 *SCE Opening Comments* at 4-6.

19 *See Reply Comments of California Community Association on the Proposed Decision,* R.20-11-033 (Nov. 16, 2021), at 3.

VI. THE COMMISSION SHOULD NOT ESTABLISH A CENTRAL PROCUREMENT PROCESS FOR OFFSHORE WIND OR INCORPORATE PROCUREMENT VEHICLES FOR SPECIFIC RESOURCES INTO THE PROGRAMMATIC APPROACH IT DEVELOPS

Offshore Wind California proposes that the Commission develop a central procurement process to ensure the development of offshore wind "[g]iven the long lead time and large scale of offshore wind projects, and the fact that a large and growing population of load in California is served by relatively small, recently created LSEs that are not well positioned to make long-term, large-scale purchases of power generated using new technology."[20] CalCCA disagrees. The Commission's procurement process, and programmatic approach that will be developed, should not be used as a vehicle for specific resource carve-outs or to develop a central procurement entity. In addition, LSEs can work together to finance such large-scale projects to the extent determined to be feasible and cost-effective. For example, California Community Power was formed in early 2021 as a Joint Powers Agency comprised of ten CCAs (representing over 3 million customers), allowing its member CCAs to combine needs to procure new, cost-effective clean energy and reliability resources.[21]

VII. CONCLUSION

CalCCA appreciates the opportunity to submit these Reply Comments.

Respectfully submitted,

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CALIFORNIA COMMUNITY CHOICE ASSOCIATION

January 19, 2022

20 *Offshore Wind California Opening Comments* at 5-6.

21 *See California Community Power,* located at https://cacommunitypower.org/; *see also "California CCAs Form Joint Buying Group, Creating Big-Time Power Purchaser,"* GTM (Feb. 9, 2021), located at https://www.greentechmedia.com/articles/read/california-ccas-form-joint-buying-group-creating-big-time-power-purchaser.

Comments on Comments on Central procurement entity implementation - draft final proposal

Initiative: Central procurement entity implementation

Comment period

Jan 07, 2022, 11:30 am - Jan 20, 2022, 05:00 pm

Submitting organizations

California Community Choice Association

California Department of Water Resources

Middle River Power, LLC

Pacific Gas & Electric

Southern California Edison

California Community Choice Association

Submitted on 01/20/2022, 02:20 pm

Contact

Shawn-Dai Linderman (shawndai@cal-cca.org)

1. Please provide a summary of your organization's comments on the Draft Final Proposal.

California Community Choice Association (CalCCA) appreciates the opportunity to comment on the California Independent System Operator's (CAISO's) Central Procurement Entity (CPE) and Resource Adequacy Availability Incentive Mechanism (RAAIM) Settlement Modification Draft Final Proposal. Despite concerns with how the current hybrid CPE framework[1] for California Public Utilities Commission (CPUC) jurisdictional entities is functioning, CalCCA generally supports the CAISO's proposal to implement changes to its tariff and systems to accommodate central procurement entities and its proposal to modify the RAAIM settlement process. In summary:

CalCCA does not oppose the CAISO's proposals related to system and local obligations for CPEs and load-serving entities (LSEs) with load in multiple Transmission Access Charge (TAC) areas;

CalCCA supports the CAISO's proposal to implement functionality to accept and validate system and flexible Resource Adequacy (RA) credits from the CPE;

CalCCA has concerns with a proposal that would first allocate local obligations to the CPE, then reallocate them to self-showing LSEs as proposed by the CAISO in CPUC's Rulemaking (R.) 21-10-002 (RA Proceeding); and,

CalCCA supports the CAISO's proposal to modify the RAAIM settlement process to eliminate the rollover of excess funds from unavailability charges above the monthly cap.

[1] See CPUC Decision (D).20-06-002.

2. Please provide comments on the system and local obligation for CPE and LSEs with load in multiple TAC Areas.

Notwithstanding CalCCA's concerns with CAISO's proposal in the CPUC's RA Proceeding to reallocate local obligations to LSEs who self-show[1], CalCCA does not oppose the CAISO's proposal to exempt a CPE or LSE with no load share in a TAC area from the cap on local obligations at their demand plus Planning Reserve Margin (PRM). CalCCA also does not oppose CAISO's proposal to cap local obligations for LSEs with load in multiple TAC areas at their demand plus PRM requirements in each TAC rather than its system obligation.

[1] *California Community Choice Association's Comments on Assigned Commissioner's Scoping Memo and Ruling*, Jan. 4, 2022: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M436/K682/436682836.PDF. *California Community Choice Association's Reply Comments on Assigned Commissioner's Scoping Memo and Ruling*, Jan. 13, 2022: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M440/K100/440100021.PDF.

3. Please provide comments on the allocation of system and flexible attributes of Local RA Resources.

CalCCA supports the CAISO's proposal to implement functionality to accept and validate system and flexible RA credits from the CPE.

4. Please provide comments on the clarification of CPM Process and Cost Allocations.

The CAISO's proposal for the Capacity Procurement Mechanism (CPM) process and cost allocations discusses how CPM cost allocation would work under the CPUC's hybrid procurement framework. The CAISO states, "As a general principle, the CPM cost allocation for an individual local RA deficiency will follow the entity assigned the local obligation by the LRA."[1] Under D.20-06-002, the CPE is the entity assigned the local obligation. Therefore, the CPE will be allocated the costs associated with local backstop procurement performed by the CAISO. The backstop costs incurred by the CPE would then be allocated to LSEs through the cost allocation mechanism (CAM). Within the CPUC process, if a self-shown resource received a local capacity requirement (LCR) reduction compensation mechanism (RCM) payment and then did not show the resource to the CAISO, then the LCR RCM payment should not be paid. This is a matter for the CPUC to address and not the CAISO.

Under this current structure, CalCCA does not oppose the CAISO's proposed CPM process and cost allocation proposal. The proposal would allocate CPM costs for an individual local RA deficiency to the entity assigned the local obligation (the CPE in the current CPUC regulations) and allocate CPM costs for collective deficiencies pro-rata to all LSEs. For collective deficiencies, the CAISO should instead determine the load share of LSEs procured for by the CPE and allocate collective CPM costs to the CPE rather than directly to LSEs. This way, both individual and collective local deficiencies are allocated to the CPE first and can then be allocated to LSEs through CAM.

The CAISO indicates that in discussions with CPE staff, there is concern around CPM cost allocation if LSEs self-show to the CPE but fail to show the same resources to the CAISO.[2] The CAISO suggests that if stakeholders would like to change the current process to address this concern, proposals should be submitted in the CPUC's RA Proceeding to modify how local allocations are made by the CPUC. The CAISO submitted a proposal to the CPUC to first allocate local obligations to the CPE, then reallocate obligations corresponding to self-shown resources to individual LSEs.[3] Under the hybrid framework, CalCCA has concerns about this proposal because reallocation would transfer the substitution obligation for shown resources from the CPE to individual LSEs. Additionally, the risk of backstop costs associated with reallocation is only offset by the LCR RCM which is very low, often $0. Given the CAISO soft offer cap for CPM at $6.31/kW-month, the offsetting revenues and cost reductions are likely to be insufficient for an LSE to self-provide a resource. CalCCA further describes the inadequate incentives and the disincentivizes that exist under the current framework and would be exacerbated if local obligations were shifted to self-showing LSEs under a hybrid model in its reply comments to R.21-10-002.[4] CalCCA does not support proposals that would further disincentivize self-showing to the CPE.

When the costs and risks of self-showing outweigh the benefit an LSE receives by self-showing, the result will be fewer resources shown to the CPE. Additionally, when many local areas are extremely tight, such that most or all local resources are needed to meet the local RA requirement, it may be impossible for the CAISO to backstop to fill deficiencies. This is because all local resources not shown by the CPE are likely already under contract and being used by other LSEs to meet their system obligations or provide substitution.

[1] CAISO Draft Final Proposal at 14.
[2] CAISO Draft Final Proposal at 14.
[3] *Phase 1 Proposals of the California Independent System Operator*, Dec. 23, 2021: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M434/K617/434617749.PDF.
[4] *California Community Choice Association's Reply Comments on Assigned Commissioner's Scoping Memo and Ruling*, Jan. 13, 2022: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M440/K100/440100021.PDF.

5. Please provide comments on the RAAIM settlement process enhancements.

CalCCA supports the CAISO's proposal to modify the RAAIM settlement process to eliminate the rollover of excess funds from unavailability charges above the monthly cap.

6. Please provide comments on the EIM Governing Body classification.

CalCCA supports the EIM Governing Body Classification of this initiative.

7. Please provide any additional input not included above related to the Draft Final Proposal.

CalCCA has no additional comments at this time.

8. Attachments

California Department of Water Resources

Submitted on 01/20/2022, 01:28 pm

Contact

Mohan Niroula (mohan.niroula@water.ca.gov)

1. Please provide a summary of your organization's comments on the Draft Final Proposal.

CDWR reiterates its comments provided on the straw proposal, in general. CAISO clarified that the local RA capping applies to monthly showing only. CDWR encourages CAISO to explore extending the capping to apply to annual showing also.

2. Please provide comments on the system and local obligation for CPE and LSEs with load in multiple TAC Areas.

CDWR reiterates its comments on the straw proposal. In addition, the CAISO clarified that the local RA capping applies only to the monthly showing.

CDWR believes that the proposed application of local RA capping for monthly RA showing should also apply to annual RA showing. LSEs with load in multiple TAC areas and having load variations uncertainty driven primarily by hydrology may experience drastic change in load, from year to year. For example, the load forecast used in LCR allocation for next year is generated some time in April of this year. For LSEs with load dependent primarily on hydrology, load forecast generated after April (for example, in August) for next year and used for the next year's annual RA plans could be drastically different. If the forecast generated in August is much lower and is used in annual RA showing, the local RA need could be much higher than the LSE's system RA need for a particular month. For an annual plan, since there is no local RA capping (as opposed to the proposed local RA capping for monthly plans), LSEs with load in multiple TAC areas could be showing much higher local RA obligations compared to its system need for that month. This requires the LSE to be subject to CPM cost for shortfall if not self-procured and an unnecessary cost of local RA procurement if procured by the LSE. Moreover, without capping of local RA in annual showing, if ISO does backstop procurement to address the shortfall in an annual showing of an LSE's local RA for a month and if in the monthly showing for the same month, the LSE's local RA is reduced due to capping at the system RA level in the respective TAC area, the ISO procured local RA capacity (above the needed monthly local obligation) in the annual process would be rendered unnecessary because the monthly local RA obligation is reduced compared to the annual showing. In that scenario, the ISO procured capacity will be a stranded cost as the LSE cannot sell it and recoup the cost. Likewise, if an LSE self-procured the capacity in the annual showing and the local RA obligation is reduced in monthly showing compared to the annual showing, the extra capacity shown in the annual beyond the needed monthly showing local obligation would have to be resold which will add extra burden and uncertainty of recouping the cost by selling in a monthly process. The issue faced by such an LSE with load in multiple TAC areas (which is identified and addressed for the monthly showing in the proposal) can also exist in the annual showing. These concerns can be addressed by applying capping of local RA obligation to the annual showing as well. Therefore, CDWR believes the local RA capping should also apply to annual plan (similar as proposed for monthly showings).

Even though annual system RA plan showing is required for 5 summer months with 90% of total system requirement, local RA capping in annual plan could be done at the 100% system RA requirement level based on the LSE's monthly demand forecast used for the annual plan. If the demand forecast for each month is not available in the annual plan (which requires only 5 summer months), the annual demand forecast for all 12 months could be available from CEC (for example, in annual LCR allocations). CDWR also believes that adjustments to the local RA obligations in annual showing relatively may not be as critical for reliability as it is for a monthly showing. The monthly RA showing determines the true obligation and resources that would be subject to the must offer obligation.

3. Please provide comments on the allocation of system and flexible attributes of Local RA Resources.

No comment.

4. Please provide comments on the clarification of CPM Process and Cost Allocations.

No comment.

5. Please provide comments on the RAAIM settlement process enhancements.

CDWR reiterates its comments provided in the straw proposal.

6. Please provide comments on the EIM Governing Body classification.

No comment.

7. Please provide any additional input not included above related to the Draft Final Proposal.

No comment.

8. Attachments

Attachments

- StakeholderCommentTemplate- CPE draft final proposal -CDWR-final-for submittal 01202022.docx

Middle River Power, LLC

Submitted on 01/20/2022, 04:45 pm

Contact

Brian Theaker (btheaker@mrpgenco.com)

1. Please provide a summary of your organization's comments on the Draft Final Proposal.

Middle River Power (MRP) does not support the CAISO's proposed modifications to the Resource Adequacy Availability Incentive Mechanism (RAAIM) settlement because the CAISO has not fully explained how its proposal resolves the identified problem. Instead, to address the narrow settlement issue the CAISO has identified, MRP recommends the CAISO consider prioritizing paying refunds before incentives while keeping the remaining aspects of the current RAAIM settlement intact.

2. Please provide comments on the system and local obligation for CPE and LSEs with load in multiple TAC Areas.

MRP understood and supported the CAISO's proposal to allow the CPE to be a scheduling coordinator and a market participant because of the possibility that the CPE might acquire physical scheduling and dispatch rights for resources. However, the CAISO's proposed modifications only allow the CPE to submit RA plans and do not allow the CPE to submit CAISO market bids for resources. As such, MRP perceives that the only reason the CAISO is designating the CPE as a scheduling coordinator is to allow the CAISO to allocate the CPE backstop procurement costs. In this sense, it may not be appropriate to consider the CPE as a market participant.

3. Please provide comments on the allocation of system and flexible attributes of Local RA Resources.

MRP has no comment.

4. Please provide comments on the clarification of CPM Process and Cost Allocations.

MRP understands that the CAISO will contonue to allocate the majority of the CPM costs to LSEs on a pro-rata basis, and only if the CPE is deficient Local RA would the CAISO allocate CPM costs directly to the CPE for its share of the deficiency rather than to LSEs on a pro-rata basis. MRP also understands that the CPE allocates its procurement costs to LSEs for whom it is procuring on a pro-rata basis. In this manner, LSEs would be allocated the same costs as if the CAISO were to directly allocate costs to the LSEs. Therefore, MRP questions the benefit of allocating CPM costs for CPE deficiencies directly to the CPE rather than the LSEs if the LSEs effectively receive the same amount of costs whether it be from the CPE or the CAISO. MRP agrees that if the CPE's cost allocation differs from the CAISO's cost allocation, then it may make sense to adjust assign costs directly to the CPE first. However, MRP does not believe that is the case at this time and therefore does not believe the CAISO's proposal is an improvement.

5. Please provide comments on the RAAIM settlement process enhancements.

MRP continues to oppose the CAISO's proposal because the CAISO has not clearly articulated why its proposal is better than other alternatives to solve the problem. Based on the background section of the draft final proposal, MRP understands that the CAISO's problem results if there is a refund obligation that arises at a point when there are not sufficient unallocated RAAIM penalty funds with which to pay a generator. Based on the discussion in the previous workshop, the CAISO stated that it was unable to prioritize refunds to be paid out of surplus RAAIM penalty roll-overs because of the neutrality rules within the Tariff. MRP does not understand the reasoning behind this issue and believes that it requires additional discussion.

MRP believes the proposal modifies several aspects of the RAAIM program and has unintended consequences. It creates fewer incentives for resources to maintain reliability in the long run because the 3X incentive cap is effectively reduced in the supplier funded RAAIM program. In the issue paper, the CAISO stated that a scheduling coordinator could use the carry-forward mechanism to hedge against its RA obligations.[1] While this statement no longer exists in the draft final proposal, MRP submits that under the CAISO's proposal, scheduling coordinators of load serving entities that also own generation would gain an advantage to hedge against their resource RA obligations when the surplus would be allocated to them rather than to generators that are not owned by LSEs. Under the CAISO's proposal, the surplus allocated to LSEs, including those that own generation, would have been an extra $927,836 in 2020 and $3,745,637 in 2019.[2] Those funds would have been rolled over to encourage better availability performance for generators were it not for the CAISO's proposal.

MRP proposes to the CAISO that if another such refund occurs, the CAISO should use RAAIM penalty funds collected within the month, along with any roll-over RAAIM surpluses funded by generators first before paying out RAAIM incentive payments. This would retain the self-funding mechanism of RAAIM while ensuring CAISO has sufficient funds to pay out any refunds. The roll-over mechanism could be used to pay for any previous refunds. While this does not ensure that the generators that would refund incentive payments in one month are the same generators that received the incentive payments for the prior month, it helps provide that the CAISO has sufficient funds for the refund.

MRP would be happy to discuss this proposal with the CAISO.

[1] Issue Paper, page 15

[2] See CAISO Annual RAAIM Report
http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=E6035720-CBC9-447A-A83D-44C9ACB74481

6. Please provide comments on the EIM Governing Body classification.

MRP has no comment.

7. Please provide any additional input not included above related to the Draft Final Proposal.

MRP requests the CAISO provide data on how often the RAAIM refund issue has occurred and the magnitude of each occurrence. This information will help MRP and other stakeholders assess the CAISO's proposal.

8. Attachments

Pacific Gas & Electric

Submitted on 01/20/2022, 04:54 pm

Contact

Matt Connolly (mhco@pge.com)

1. Please provide a summary of your organization's comments on the Draft Final Proposal.

Pacific Gas & Electric Company (PG&E) appreciates the CAISO's continued efforts in this initiative to update the tariff language and seek stakeholder input on incorporating the Central Procurement Entity (CPE) construct. PG&E continues to support many of the CAISO's proposals outlined in the Draft Final Proposal and the Draft Tariff Language and offers the following comments for consideration.

2. Please provide comments on the system and local obligation for CPE and LSEs with load in multiple TAC Areas.

PG&E appreciates CAISO's response to its previous comments and supports the modification "to exempt any entity without load share in a TAC area that their local obligation could not exceed their system obligation in each TAC area." (Draft Final Proposal, p.12).

3. Please provide comments on the allocation of system and flexible attributes of Local RA Resources.

As noted in our comments[1] on the CAISO's draft tariff language, PG&E requests the CAISO's consideration of a default methodology to allocate the system and flexible attributes of CPE-procured Local RA Resources to individual load serving entities (LSE) if the assignment has not been determined by local regulatory authority (LRA). As discussed on the stakeholder call on January 13, 2022, a default methodology could be based on a load share ratio calculation that is limited to LSEs represented by the CPE (and does not include non-CPUC jurisdictional LSEs).

[1] Comments on Central Procurement Entity Implementation - Draft Tariff Language, Pacific Gas & Electric, January 6, 2022 at https://stakeholdercenter.caiso.com/Comments/AllComments/a1bfaf30-69cc-4ae9-bae4-76005beacd29#org-a1d14efd-92ac-4f9c-820e-6b2b1503a72c

4. Please provide comments on the clarification of CPM Process and Cost Allocations.

PG&E appreciates the attention and consideration the CAISO has given to the CPM cost allocation modifications to recognize the role of the CPE in the CPM process; however, PG&E still has concerns with the CAISO's proposal and maintains its position as noted in previous comments in this initiative and within the CPUC's current Rulemaking (21-10-002).[1]

[1] *See* PG&E's Opening Comments on Phase 1 Proposals in CPUC Rulemaking 21-10-002, pp. 10-12. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M436/K656/436656171.PDF

See also PG&E's Reply Comments on Phase 1 Proposals in CPUC Rulemaking 21-10-002, pp. 3-8. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M440/K092/440092142.PDF

5. Please provide comments on the RAAIM settlement process enhancements.

As noted in prior comments, PG&E supports the CAISO's proposed enhancements to the RAAIM settlement process.

6. Please provide comments on the EIM Governing Body classification.

PG&E agrees with the CAISO's classification that this initiative falls outside of the EIM Governing Body's advisory role.

7. Please provide any additional input not included above related to the Draft Final Proposal.

Based on the stakeholder call on January 13, 2022, PG&E understands that the CAISO plans to update its proposed tariff language in Section 4 in response to stakeholder concerns by removing the additional language proposed in Section 4.18 of the draft tariff language in its entirety that included the responsibilities of the Scheduling Coordinator of the CPE mirroring that of a convergence bidding entity. PG&E supports CAISO's proposal on the stakeholder call to remove Section 4.18 and the proposed pro forma agreement referenced within and instead allow the CPE to be represented by the Scheduling Coordinator of the LSE that its shares. PG&E further supports the need for a distinct Scheduling Coordinator ID to ensure separation of the CPE and LSE functions under a shared Scheduling Coordinator.

PG&E also supports Southern California Edison Company's comment made on the stakeholder call on January 13, 2022 to remove the proposed language in Section 4.18 that restricts the Scheduling Coordinator of the CPE from submitting bids into the CAISO's energy market. As mentioned on the call and in previous comments, the CPE is encouraged to procure dispatch rights under CPUC Decision 20-06-002 and should maintain the ability to submit bids under the CAISO Tariff when applicable.[1]

With respect to both of the updates to the proposed tariff language as discussed on the stakeholder call and reiterated here, PG&E believes that the proposed CPE definition in Appendix A will need to be modified accordingly as well.

[1] D.20-06-002, pp. 49-50.

8. Attachments

PG&E has no attachments to provide.

Southern California Edison

Submitted on 01/20/2022, 03:05 pm

Contact

Kathy Wong (kathy.wong@sce.com)

1. Please provide a summary of your organization's comments on the Draft Final Proposal.

Southern California Edison (SCE) supports the CAISO's *Central Procurement Entity Implementation and RAAIM Settlement Modification, Draft Final Proposal's* (Draft Final Proposal's) recommendation to exempt a Central Procurement Entity (CPE) from the existing tariff provision that a local resource adequacy (RA) obligation cannot exceed the system obligation in each transmission access charge (TAC) area. However, SCE reiterates that Load Serving Entities (LSEs) outside of their TAC who self-show should not be assigned any local RA obligation for that TAC area.

SCE also supports the CAISO's proposal to modify CIRA to match the allocation of system and flexible attributes with the exact quantity of local RA shown by the CPE. Finally, SCE agrees with the CAISO's draft tariff changes, as presented at the January 13 workshop, to update its tariff and systems, as it relates to the Capacity Procurement Mechanism (CPM) and cost allocations, and to provide flexibility to accommodate potential changes the California Public Utilities Commission (Commission or CPUC) may adopt through the CPUC RA Phase 1 proceeding, as it relates to self-showing resources.

2. Please provide comments on the system and local obligation for CPE and LSEs with load in multiple TAC Areas.

In its Draft Final Proposal, the CAISO states that "[i]n instances where a CPE or LSE does not have load share in a specific TAC area, but is assigned a local obligation by a LRA[)], the CAISO proposes to exempt the entity from this provision of the tariff and develop software enhancements to support this exemption."[1] SCE supports that proposal so that LSEs who commit to self-show capacity will be required to meet their assigned obligation. SCE also supports CAISO's proposal that an LSE's local RA obligation cannot exceed its system obligation in each TAC area for the applicable month.

Regarding the applicability of this exemption to an LSE outside the CPE's TAC area, SCE reiterates its position, as discussed in its filings in the CPUC's RA Phase 1 proceeding, that an LSE outside of the CPE's TAC area should not be assigned any local RA obligation for that TAC area since it does not receive any of the CAM credits or other benefits that LSEs within the TAC area receive.[2] While the CAISO's proposal here is not conflicting with SCE's position, in SCE's view, the CAISO should not assign a local obligation to an LSE who self-shows local capacity to a CPE if that LSE is outside the CPE's TAC area. SCE strongly believes by doing so, it will increase incentives for self-showing.

Further, since the CAISO proposal is based on the existing Tariff Section 40.3.2 (a), which provides that an LSE will not be assigned a local obligation in excess of "its applicable Demand and Reserve Margin requirements for the applicable month", SCE seeks clarification regarding the purpose of this existing provision, the history of why this provision was introduced, the issue(s) it is trying to address, and its desired outcome. Having that information will help SCE and other stakeholders better understand the context of this provision and how it is intended to be applied.

[1] *See* SCE's Phase I Proposal p. 4.

[2] Draft Final Proposal p. 11.

3. Please provide comments on the allocation of system and flexible attributes of Local RA Resources.

SCE agrees with CAISO's proposal to implement separate fields in the LRA Credit templates in CIRA to accept and validate system CPE cost allocation mechanism (CAM) credits to match the allocation of system attribute of local RA resources with the exact quantity of local RA resources shown by the CPE, and to match the allocation of flexible attribute with the exact quantity of flexible attribute of the local RA resources shown by the CPE. Because local and system attributes of RA resources cannot be unbundled, it is reasonable for the self-showing LSE to receive the same amount of system credits equal to the same quantity of local RA resources self-shown and is expected to be shown by that LSE.

4. Please provide comments on the clarification of CPM Process and Cost Allocations.

As discussed in the January 13 CAISO workshop on its proposals for its draft tariff modifications, SCE understands that the CAISO is addressing changes that are required to implement the CPE process, prior to the proposed modifications. However, SCE supports the CAISO in making whatever updates that are necessary to its system related to the CPM process and cost allocations, so that it can accommodate CPE modifications adopted by the CPUC, particularly as it relates to concerns regarding self-showing resources.

5. Please provide comments on the RAAIM settlement process enhancements.

SCE supports the CAISO's proposal to simplify the RAAIM settlement process by eliminating the rule that unavailability charges assessed in excess of the monthly cap will roll-over to fund allocations in future months. CAISO proposes that excess funds based on activity in that month should be based on the allocation formula that currently applies to the year-end allocation and to allocate excess RAAIM charges for Generic RA or Flexible RA to metered demand.

6. Please provide comments on the EIM Governing Body classification.

SCE has no comment at this time.

7. Please provide any additional input not included above related to the Draft Final Proposal.

SCE as no additional input at this time.

8. Attachments

N/A