

APRIL FILINGS



April 17, 2023

VIA ELECTRONIC MAIL

Energy Division
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102
Email: EDRetailChoiceSection@cpuc.ca.gov

Re: California Community Choice Association's Comments on Draft Resolution E-5258. Effective Dates for the Expansions of Community Choice Aggregators: Central Coast Community Energy and East Bay Community Energy

Dear Energy Division,

Pursuant to Rule 14.5 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure, and the Comment Letter accompanying Draft Resolution E-5258, California Community Choice Association¹ (CalCCA) submits these comments on Draft Resolution E-5258, Effective Dates for the Expansions of Community Choice Aggregators (CCAs): Central Coast Community Energy (CCCE) and East Bay Community Energy (EBCE) (Draft Resolution).

SUMMARY

The Draft Resolution goes to destructive lengths to conceal its true aim: to punish EBCE and CCCE for past Resource Adequacy (RA) program deficiencies. The Draft Resolution:

- Unabashedly bypasses long-standing Commission processes, adopting and enforcing broad new rules outside of the related rulemaking proceedings – Rulemaking (R.) 20-10-002 and R.17-06-026 – through what is essentially a targeted enforcement action. Most glaring, the Draft Resolution prematurely adopts and enforces an Energy Division staff RA enforcement proposal pending consideration in R.20-10-002.

¹ California Community Choice Association represents the interests of 24 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, Energy For Palmdale's Independent Choice, Lancaster Choice Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

- Encourages the Commission to exceed its limited statutory authority over CCAs by delaying indefinitely the launch of EBCE and CCCE expansions and misapplying statutory authority governing cost recovery and RA enforcement. The Draft Resolution ignores the Commission’s limited scope of authority over CCA implementation plans, misapplies the Commission’s authority to set the “earliest possible date” for CCA implementation under Public Utilities Code Section 366.2(c)(8), and creates by its own admission a “new and distinct” cost shift theory not specified by statute or prior regulation.
- Fails to connect the dots between the CCAs’ RA deficiencies and the cost shift to bundled customers. The Commission’s own decisions make clear that RA deficiencies did not drive or even influence the procurement of excess incremental resources or implementation of the Emergency Load Reduction Program (ELRP). There is no evidence examining the potential interplay, if any, between RA deficiencies and any market costs; factors such as RA supply sufficiency, resource availability, sales of investor-owned utility (IOU) excess resources, and load variations require consideration to reach the conclusion that a particular load-serving entity (LSE) is responsible for such costs.
- Fails to address the affordability, climate, and environmental impact of its proposed delay of EBCE’s expansion into Stockton, a “disadvantaged community” (DAC) under the definition endorsed by the Commission’s own Environmental and Social Justice Action Plan (ESJ), even though its ESJ and Enforcement Policies commit that all Commission decisions will prioritize and address such impacts on DACs.

The Draft Resolution is beyond repair and should be withdrawn.

BACKGROUND

The Draft Resolution effectively suspends indefinitely the already-certified amended implementation plans of CCCE and EBCE to expand their current service. EBCE submitted an amended implementation plan to expand service to the City of Stockton on September 22, 2022,² and CCCE submitted an amended implementation plan to expand service to the City of Atascadero on December 8, 2022.³

² *EBCE Addendum No. 2 to the Community Choice Aggregation Implementation Plan and Statement of Intent to Address EBCE Expansion to the City of Stockton* (Dec. 8, 2022), located at https://res.cloudinary.com/diactiwk7/image/upload/v1670611946/EBCE_Addendum_2_CCA_Implementation_Plan_120822_e2sqja.pdf.

³ *Addendum No. 4 to the Community Choice Aggregation Implementation Plan and Statement of Intent Addressing Central Coast Community Energy’s Expansion to Include the City of Atascadero* (Sept. 22, 2022), located at <https://3cenergy.org/wp-content/uploads/2022/12/Addendum-No.-4-to-the-CCCE-Community-Choice-Aggregation-Implementation-Plan-.pdf>.

In letters dated March 8, 2023, the Commission certified that EBCE's and CCCE's implementation plans are complete and compliant with the requirements of Public Utilities Code Section 366.2(c).

The letters denied, however, the effective dates requested by EBCE and CCCE without setting an alternative date. The letters gave no information on why Energy Division was denying the requested effective dates, stating only that "Energy Division will provide further guidance on the matter." In response, on March 10, 2023, EBCE and CCCE requested pursuant to Public Utilities Code Section 366.2(c)(8) that the Commission confirm April 1, 2024, and January 1, 2024, respectively as the earliest possible effective dates for their expansions.

On March 27, 2023, Energy Division issued Draft Resolution E-5258 suspending implementation of EBCE's and CCCE's service expansions indefinitely. While the Draft Resolution purports to set January 1, 2025, as the earliest possible effective date for the expansions of service for both CCAs, it leaves the date "subject to modification by further Commission Order."⁴ The conditional nature of the January 1, 2025, effective date leaves the implementation plans suspended indefinitely.

The Draft Resolution's suspension of the amended implementation plans is grounded in noncompliance by EBCE and CCCE with their requirements under the Commission's RA program for 2021 and 2022.⁵ Suspension of an implementation plan is not a current remedy under the existing RA enforcement mechanism but has been proposed by Energy Division staff and is pending in R. 21-10-002.⁶ Likely because the Commission has not yet adopted this mechanism, the Draft Resolution cloaks its aim as an exercise of its authority to prevent cost shifting from CCA customers to IOU bundled customers.⁷

COMMENTS

- 1. The Draft Resolution Unlawfully Creates and Enforces New Regulations**
 - a. Draft Resolution End Runs R.21-10-002 in an Attempt to Cure Perceived Failures in the RA Program's Enforcement Mechanism**

The Draft Resolution attempts to cure perceived failures of the Commission's RA program in addressing the consequences of RA non-compliance. Changes to the RA enforcement framework must instead be addressed, as the Commission addresses all such changes, in the pending RA rulemaking, R.21-10-002.

⁴ Draft Resolution at 2.

⁵ *See id.* at 7-10.

⁶ *See infra*, Section 1.a.

⁷ *Ibid.*

The Draft Resolution expressly acknowledges that its decision to delay expansion is intended to “fully redress harms caused by a failure to meet Resource Adequacy requirements”⁸ and penalize two CCAs for past RA non-compliance. In fact, the only CCA action the Commission identifies to justify the delay is non-compliance with RA requirements. The Draft Resolution drills down on “Resource Adequacy Program Violations” by the CCAs, providing a list of these violations for effect.⁹ Six of the ten substantive findings made in the Draft Resolution address the CCAs’ past or future compliance with RA requirements.¹⁰ In short, RA non-compliance is the sole driver for the expansion delay.

The Commission’s RA program, governed by Public Utilities Code Section 380, places requirements on all LSEs – CCAs, Electric Service Providers (ESPs), and IOUs. The RA program has a clear compliance and penalty framework.¹¹ The Draft Resolution describes those penalties, including administrative penalties and penalties for deficiencies.¹² An LSE that fails to meet its requirements must pay a pre-determined penalty, which increases by multiples as penalties accumulate. The current RA framework does not provide the Commission authority, however, to use expansion delay as a penalty for a CCA’s failure to meet its RA requirements.

The Draft Resolution suggests, however, that its RA program enforcement scheme leaves a gap that needs to be addressed:

... payment of a Resource Adequacy violation does not fully redress harms caused by a failure to meet Resource Adequacy program requirements, most notably the CCA’s failure to timely procure the required level of capacity. Rather, penalties are intended to deter non-compliance, and payments on citations are remitted to the State general fund. The penalty amounts do not reflect the cost to other ratepayers when an entity fails to procure as required to maintain reliability, nor do they provide a mechanism to reimburse ratepayers for cost shifting that may be caused by an entity failing to meet its Resource Adequacy requirements.¹³

⁸ *Id.* at 7.

⁹ *Id.* at 5-7.

¹⁰ *Id.*, Findings 5-10.

¹¹ See D.20-06-031, *Decision Adopting Local Capacity Obligations for 2021-2023, Adopting Flexible Capacity Obligations for 2021, and Refining the Resource Adequacy Program*, R.19-11-009 (June 25, 2020), Ordering Paragraph (O¶) 20, at 96.

¹² Draft Resolution at 6 (citing D.11-06-022, *Decision Adopting Local Procurement Obligations for 2012 and Further Refining the Resource Adequacy Program*, R.09-10-032 (Oct. 29, 2009), Appendix B; D.20-06-031, at O¶ 20).

¹³ Draft Resolution at 7.

If the RA enforcement scheme has, in fact, failed, that failure should be addressed in a rulemaking with notice to potentially affected parties and an opportunity to be heard. Righting the perceived “wrongs” of the RA program in a resolution targeted at the performance of two CCAs end runs the Commission’s own rulemaking process.

There could not be clearer proof of this end run than the fact that this same RA enforcement mechanism is currently pending before the Commission but has not yet been adopted. The Energy Division Staff, who have also prepared the Draft Resolution, have proposed the following remedy in the current RA rulemaking, R.21-10-002:

To address the potential reliability issues that arise with continued expansion of LSEs that are failing to meet their current summer RA obligations, ED staff propose that a community choice aggregator (CCA) or electric service provider (ESP) must be in good standing in meeting its RA requirements in order to take on new customers. Specifically, ED staff proposes that any CCA or ESP with a deficiency of greater than 2.5% of its system RA requirement on a month ahead RA filing during the previous two calendar years should not be able to expand and take on new any new customer load for the following year. For example, any LSE with RA requirement deficiencies in 2021 or 2022, would not be eligible to expand to serve new load in 2023 for service in 2024.¹⁴

If this proposal sounds familiar, it is; it is precisely what the Energy Division attempts to effectuate in the Draft Resolution. By skipping over the necessary procedural hoops in the RA proceeding and *sua sponte* applying the mechanism, the Draft Resolution skirts an on-going rulemaking process.

Ignoring this process violates the due process rights afforded to CCAs participating in the regulatory process. As recently recognized by the Commission, “an elementary and fundamental requirement of due process is notice reasonably calculated to apprise interested parties of the content and pendency of the action and afford them an opportunity to present their objections.”¹⁵ For this reason, the Commission regularly denies party requests for relief regarding an issue that

¹⁴ R.21-10-002, *Administrative Law Judge’s Ruling on Energy Division’s Phase 3 Proposals* (Jan. 20, 2023), Appendix A, Energy Division Proposals for Proceeding R.21-10-002, at 34.

¹⁵ D.21-11-035, *Order Denying Rehearing of Resolution E-5150*, Application of California Solar & Storage Association, Solar Energy Industries Association and Vote Solar for Rehearing of Resolution E-5150, A.21-07-013 (Nov. 18, 2021), at 3; *see also People v. Western Air Lines*, 42 Cal.2d 621, 632 (1954) (“due process as to the [California Public Utilities Commission’s] ... action is provided by the requirement of adequate notice to a party affected and an opportunity to be heard before a valid order can be made”).

is being addressed in a pending proceeding.¹⁶ Critically, the enforcement mechanism has not been adopted by the Commission and legal challenges to such an order have not been exhausted. By skipping over the rulemaking process to unilaterally cure perceived failures in the RA enforcement process and achieve its goals of delaying CCA expansion, the Commission has denied due process and acted unlawfully.

b. The Draft Resolution Unilaterally and Unlawfully Implements a New Cost-Shift Regulation Outside of the Existing Rulemaking Process

The Draft Resolution creates a new cost-shift theory out of whole cloth to justify its new RA enforcement mechanism. It finds that “[b]ecause the Commission cannot conclude that Central Coast Community Energy and East Bay Community Energy’s planned expansions will not cause further cost shifting, it would be unreasonable to confirm the proposed effective dates in 2024.”¹⁷ Camouflaging the Draft Resolution as an enforcement of the cost-shift prohibition under Public Utilities Code Section 366.2(d)-(f), however, does not eliminate the procedural flaws. The Draft Resolution does not employ a cost-shift category identified by statute or previously adopted in the cost-shift rulemaking, R.17-06-026; instead, it finds it “necessary to address a new and distinct type of cost shifting that is resulting from LSEs who fail to procure their required capacity under the Resource Adequacy program.”¹⁸ This new type of cost shift is not fully defined nor its calculation methodology determined, did not arise in any proceeding, and involves only two parties. The Draft Resolution, if adopted, would unilaterally and unlawfully establish an impactful, and material rule that affects more than thirty load-serving entities in the State without due process.

The Commission has previously defined cost-shifting and adopted regulations in formal proceedings with notice to all parties and an opportunity to be heard. The Power Charge Indifference Adjustment (PCIA), which is the most significant measure to avoid cost-shifting, was adopted after nearly two years of rulemaking.¹⁹ Each time the Commission modifies the PCIA methodology, it provides notice and an opportunity to be heard in the PCIA Rulemaking,

¹⁶ See, e.g., D.03-02-035, *Order Modifying Decision 02-07-032, for Purposes of Clarification, and Denying Rehearing, as Modified*, Application of Pacific Gas and Electric Company for Verification, Consolidation, and Approval of Costs and Revenues in the Transition Revenue Account, A.98-07-003 (Feb. 13, 2003) (“[b]ecause these issues are currently being considered in this pending proceeding, we need not and do not address these rehearing issues in today’s order”).

¹⁷ Draft Resolution at 11.

¹⁸ *Id.* at 9 (emphasis added).

¹⁹ See D.07-01-025, *Order Adopting Modifications to the Cost Responsibility Surcharge Applicable to Community Choice Aggregators*, R.03-10-003 (Jan. 25, 2007) (adopting the PCIA for CCA customers after workshops and comments after first addressing “ratepayer indifference” issues in D.04-12-046 and addressing changes required of the PCIA adopted for direct access and departing municipal customers in D.06-07-030).

R.17-06-026.²⁰ While the Draft Resolution appears to have been served on the service list in that proceeding, there has been no rulemaking process to define or develop a calculation methodology for the “new and distinct type of cost shift.”

Here again, the Draft Resolution denies parties due process in the adoption of a material “new and distinct” rule outside of its rulemaking process.

2. The Draft Resolution Exceeds the Commission’s Limited Statutory Authority Over CCAs

The Commission has acknowledged its narrow role authorized by Assembly Bill 117 in overseeing local government’s implementation and operation of a CCA. The Commission has concluded that AB 117 does not confer authority for “general regulatory oversight of CCAs.”²¹ The Commission further clarified: “we do not believe that AB 117 intended to give this Commission broad jurisdiction over CCAs.”²² In focusing specifically on the regulatory process for considering CCA implementation, it found that: “AB 117 does not provide us with authority to approve or reject a CCA’s implementation plan or to decertify a CCA.”²³ Importantly, it also concluded that its jurisdiction was limited by the express terms of the statute: “We assume that if the Legislature intended for us to regulate the CCA’s implementation plan in other ways, the Legislature would have included explicit language in the statute with regard to its intent.”²⁴ The Draft Resolution exceeds this narrow grant of jurisdiction by basing the “earliest possible date” on RA compliance and leaving the expansion date indefinite and uncertain.

a. The Commission Has No Authority to Base the “Earliest Possible Date” for Expansion on a CCA’s Resource Adequacy Compliance History

The Commission’s performance of its duty under Public Utilities Code Section 366.2(c)(8) to “establish the earliest possible date” for a CCA to launch or expand, while

²⁰ R.17-06-026, *Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment* (July 10, 2017) (opening the PCIA proceeding, which currently remains open and through which the Commission is considering modifications to the market price benchmarks for the PCIA).

²¹ D.05-12-041, *Decision Resolving Phase 2 Issues on Implementation of Community Choice Aggregation Program and Related Matters*, R.03-10-003 (Dec. 15, 2005), Conclusion of Law (COL) 2, at 60; *see also id.*, COL 1, at 60 and Finding of Fact (FOF) 2, at 56.

²² *Id.* at 16; *see also* D.12-09-021, *Order Denying Rehearing of Resolution E-4250*, Application of Pacific Gas and Electric Company for Rehearing of Resolution E-4250, A.10-05-015 (Sept. 13, 2012) (the Commission acknowledges its “limited jurisdiction over CCAs” in contrast to its “general jurisdiction” over IOUs).

²³ D.05-12-041, at 4; *see also id.*, at 14 (“we find nothing in the statute that directs the Commission to approve or disapprove an implementation plan or modifications to it. Nor does the statute provide explicit authority to “decertify” a CCA or its implementation plan”).

²⁴ *Id.* at 15.

ministerial, is a critical element of the framework for implementation or expansion of CCA service adopted in AB 117. By failing to perform its duty as required, the Commission frustrates the CCA implementation and expansion process for not only the CCA, but for the local government who elected CCA, the ratepayers in the affected area, and the IOUs who are required to coordinate the transition.

The process for CCA implementation in a new jurisdiction is complex and requires compliance with a strict timeline based on the Commission’s designated “earliest possible date.” For example, in the case of an expansion, a CCA works with the new local jurisdiction long in advance of launching service. The process requires the local government joining the CCA to pass an ordinance authorizing its action,²⁵ and then requires extensive, ongoing coordination between the CCA and the local government.²⁶ It requires providing new customers clear notice of the change in service in many respects but, most critically, clear notice of the timing of the transition.²⁷ In addition, the process requires CCAs to work with the IOU in whose territory it will provide the new service to both notify the IOU of the planned commencement of service, and to plan for the transfer of applicable accounts within a quick 30-day period after CCA notification of its service commencement.²⁸ Also necessary for launch or expansion of service is the procurement of electricity to serve customers. The timing of these prerequisites to service are by necessity based entirely on the “earliest possible date” set by the Commission and must be established well in advance of a CCAs launch or expansion of service.

The statute anticipated this extensive process in Public Utilities Code Section 366.2(c)(8). The statutory requirement that the Commission “shall designate” the earliest possible launch date gives the CCA the date certain it needs to notify customers, plan its launch or expansion, procure electricity, and provide all relevant notices to the IOU. As a result, the Commission’s clear establishment of the “earliest possible date” within the confines of the statute is not only required, but necessary to provide certainty for an effective implementation or expansion. In setting an earliest possible effective date, the statute permits the Commission to “tak[e] into consideration the impact on any annual procurement plan of the electrical corporation that has been approved by the commission.”²⁹ By instead setting the earliest possible date for the expansion on the CCAs’ RA compliance history, however, the Draft Resolution fails to set the earliest possible date in the manner required by law.

Nowhere does the Draft Resolution state that its January 1, 2025, date for expansion is based on an annual procurement plan of any IOU. It explains the date is needed “to allow the Commission to take further actions to ensure expansion of these CCAs will not cause impermissible cost shifting onto IOU customers.”³⁰ It concludes that “[g]iven the history and

²⁵ Public Utilities Code § 366.2(c)(12).

²⁶ *See, e.g., id.* § 366.2(c).

²⁷ *Id.* § 366.2(c)(15).

²⁸ *Id.* § 366.2(c)(18)-(19).

²⁹ *Id.*, § 366.2(c)(8).

³⁰ Draft Resolution at 10.

pattern of Resource Adequacy deficiencies by CCCE and EBCE, we find they contributed to cost shifting onto IOU bundled customers.”³¹ It further explains that the Commission “has concerns regarding their ongoing ability to meet Resource Adequacy requirements.”³² The Draft Resolution turns on RA compliance, not on an IOU procurement plan. The Draft Resolution thus considers factors other than the impact of an IOU’s annual procurement plan in contravention of Public Utilities Code Section 366.2(c)(8)’s limited, express authorization for the Commission to only consider those impacts.³³ The Commission therefore steps beyond its limited statutory authority.

b. The Commission Has No Authority to Reserve the Right to Later Modify the Designated “Earliest Possible Date”

Public Utilities Code Section 366.2(c)(8) provides that “[t]he commission shall designate the earliest possible effective date for implementation of a community choice aggregation program.”³⁴ The Draft Resolution, purporting to reserve the right to change the designated date, does not stay within the bounds of the statute. The Draft Resolution states:

The earliest effective date for Central Coast Community Energy and East Bay Community Energy’s proposed expansions is January 1, 2025, unless the date is modified by further order of the Commission.³⁵

The Draft Resolution also states that the date is conditioned on “further actions to ensure the expansions will not cause impermissible cost shifting.”³⁶ However, no further process or

³¹ *Id.* at 9.

³² *Ibid.*

³³ In addition, long-standing principles of statutory interpretation require that a statute that provides explicit guidance implies a limitation on any other exercise of authority. This doctrine, “*expressio unius est exclusio alterius*” (expression of the one is the exclusion of the other), remains a foundational statutory interpretation principle today. In utilizing the doctrine to interpret Public Utilities Code Section 366.2(c), the Commission stated:

A general rule of statutory interpretation suggests that where a statute provides specific guidance – in this case on the Commission’s role and authority – its silence in a related section or on related issues implies a limit on that role and authority. Here, the statute does require the CCA to file the plan here and gives the Commission authority to request information about the plan and to register the CCA. We assume that if the Legislature intended for us to regulate the CCA’s implementation plan in other ways, the Legislature would have included explicit language in the statute with regard to its intent.

D.05-12-041, at 15 (citations omitted).

³⁴ Public Utilities Code § 366.2(c)(8) (emphasis added).

³⁵ Draft Resolution, O¶ 2, at 12 (emphasis added).

³⁶ *Id.*, Finding 12, at 12.

schedule is described that would provide a date certain as required by the statute, or that would give the CCAs a secure milestone upon which to base the expansions.

By expressly requiring the designation of the “earliest possible date” under Public Utilities Code Section 366.2(c)(8), the Commission is not authorized under the statute to condition such designation on anything else.³⁷

3. The Draft Resolution Fails to Demonstrate that CCA Deficiencies Caused Incremental Excess Procurement and ELRP Costs

The Draft Resolution summarily finds that the CCAs have shifted the costs of incremental excess procurement and ELRP resources to bundled customers.³⁸ It fails, however, to provide evidence that the cost shift in fact occurred.

The Commission directed the IOUs to procure the resources “to maintain reliability of the grid during extreme weather events.”³⁹ Decision 21-12-015 makes clear that the net costs associated with the IOU supply side procurement “shall be passed through to all benefitting customers consistent with the existing Cost Allocation Mechanism.”⁴⁰ Similarly, ELRP costs are recovered through distribution rates from all customers.⁴¹ RA deficiencies did not drive or even influence this procurement.

The conclusion that the CCAs caused the costs in question, or even uniquely benefitted from those costs, has not been supported by evidence. The Draft Resolution does not demonstrate that “but for” the CCAs’ deficiencies, the excess procurement would not have been taken, nor that the use of ELRP resources would not have been triggered. To draw that linkage requires demonstrating two key facts and ignores the potential that other LSEs may have contributed to the problem.

a. The Draft Resolution’s Argument Is Missing Critical Analytical Steps

To demonstrate cost shifting requires a showing that there were sufficient resources in the RA market to ensure compliance by all LSEs in the Commission’s RA program, and there were resources available for procurement. It is possible that all RA resources available for procurement were procured by LSEs and that the supply was insufficient to cover all

³⁷ See *supra*, note 34. The statutory interpretation principle *expressio unius est exclusio alterius*, which the Commission relied upon in interpreting § 366.2 in 2005 and in other cases as set forth above, applies equally to the conditional nature of the Draft Resolution’s expansion date.

³⁸ Draft Resolution, Findings 5 and 6, at 11.

³⁹ D.21-12-015, O¶ 2, at 160.

⁴⁰ *Id.*, O¶ 11, at 163.

⁴¹ See PG&E Advice Letter 6805-E (Dec. 29, 2022), Tables 1 and 2, at 4-5. Demand Response Expense Balancing Account (DREBA) balance is quantified and identified as being included in distribution revenue requirements. *Id.*

requirements. CalCCA’s 2021-2022 Stack Analysis shows that the overall system was short capacity to meet requirements:⁴²

September NQC (MW)	2021	2022	2023
1 CAISO 1-in-2 Load	45,966	46,319	46,829
2 Reserve Margin (15%)	6,895	6,948	7,493
3 Total RA Demand	52,861	53,267	54,322
4 NQC List	44,843	46,923	47,304
5 Event-Based Demand Response	1,212	1,136	1,090
6 Imports	6,409	5,500	5,500
7 Thermal Plant Derate	(557)	(650)	(717)
8 Excess IOU Resources Above PRM (D.21-12-015)	-	(206)	(206)
9 Supply-Side Emergency Reliability Procure. (D.21-12-015)	-	(1,125)	(1,125)
10 Retention for Substitution	(619)	(619)	(619)
11 Total RA Supply	51,289	50,959	51,227
12 Surplus Supply (Deficit)	(1,572)	(2,308)	(3,094)
13 Expected New Resources	-	-	1,695
14 Surplus Supply (Deficit) with New	(1,572)	(2,308)	(1,399)

If that is the case, it was not the CCAs failure to meet their requirements that caused reliance on excess or extraordinary resources, but market scarcity in general.

To demonstrate cost shifting requires a showing that more resources would have operated in the market when energy was needed had the CCAs procured their full requirements. It is possible that all available resources were already selling into the market – as RA resources or economic resources – during periods of shortages. It is also possible that some or all of the problem was caused by unanticipated load surges due to weather conditions.⁴³ The monthly RA showing for September 2022 was 49,748 MW, which is higher than September’s 2021 monthly showing of 48,623 MW.⁴⁴ But load was even higher: “With historic heat in many parts of

⁴² The Commission issued its report on 2021 RA procurement in March, 2023. *See 2021 Resource Adequacy Report* (Apr. 2023) (Report). https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2021_ra_report.pdf The Report shows that, collectively, all 2021 system RA requirements under the Commission’s RA program were met in all months. It does not, however, attempt to show the overall RA supply-demand balance in the CAISO-wide market for 2021. Moreover, it does not show the individual deficiencies and excesses that occurred to meet those requirements. To fully understand market dynamics requires a comparison of IOU excess procurement with other LSE deficiencies.

⁴³ Using 20 years of historic weather, Sept 2022 was a 1-in-11 weather event. Using 28 years of historic weather, Sept 2022 was a 1-in-25-year weather event. California ISO, *Summer Monthly Performance Report, Sept 2022* (Summer Performance Report), at 25. <http://www.aiso.com/Documents/SummerMarketPerformanceReportforSeptember2022.pdf>.

⁴⁴ *Id.* at 14.

California, electricity use on the ISO grid hit a peak of 52,061 megawatts (MW), breaking previous load records by almost 2,000 MW.”⁴⁵

Finally, even if the Draft Resolution could demonstrate a link between the CCA deficiencies and market costs, those costs must be recovered based on the Commission’s determination of cost recovery at the time “the commitment to incur the cost is made,” as discussed above.

b. The CCA Deficiencies May Have Been Caused, in Part, by PG&E’s Failure to Sell Excess Capacity from Its Portfolio

The Commission’s rush to punish these two CCAs for RA deficiencies may hold the wrong LSEs accountable. PG&E has admitted in its ERRA Compliance Application that it had 923 MW of “excess RA” it did not sell to LSEs like EBCE and CCCE during the summer months of 2022.⁴⁶ PG&E’s Excess Resource Report for 2022, which is public, shows that the 923 MW were counted as excess in June – October 2022 as follows:⁴⁷

Project/Resource Name	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22
2. Excess Resources from IOU Portfolio					
Above 15% PRM	<i>MW to be claimed for CAM Cost Recovery</i>				
Excess Resources from IOU Portfolio	103.70	183.14	148.97	156.70	330.00

The Commission has identified PG&E's ERRA Compliance application as the place for parties to determine if PG&E managed its portfolio prudently during 2022, including determining the amount of “excess RA” in its portfolio, the amount of that excess RA offered for sale, whether PG&E received actionable bids to purchase that excess RA during 2022, and whether PG&E’s rejection of bids, if there were any, for that excess RA was appropriate.⁴⁸

⁴⁵ *Id.* at 35. The September 6 peak load was 17% above the CEC month-ahead forecast, meaning that September RA fell short of actual load by 2,313 MW. *Id.* at 49.

⁴⁶ A.23-02-018, *Pacific Gas and Electric Company Application for Compliance Review of Utility-Owned Generation Operations, Portfolio Balancing Account Entries, Energy Resource Recovery Account Entries, Contract Administration, Economic Dispatch of Electric Resources, Utility-Owned Generation Fuel Procurement, and Other Activities for the Period January 1 Through December 31, 2022*, Prepared Testimony (Feb. 28, 2023), Ch. 12 at 12-15.

⁴⁷ *IOU Excess Reporting Summary, 2022*, Pacific Gas and Electric Company, Row 53, Columns D-H, located at: [Resource Adequacy Compliance Materials \(ca.gov\)](https://www.pge.com/resources/energy-operations/ra-reports/IOU-Excess-Reporting-Summary-2022)

⁴⁸ *See, e.g.,* A.22-02-015, *Assigned Commissioner’s Scoping Memo and Ruling*, at 2-3 (including in scope “Whether PG&E administered resource adequacy procurement and sales consistent with its Bundled Procurement Plan” and “Whether PG&E, during the record period, prudently administered and managed, in compliance with all applicable rules, regulations and Commission decisions, including but not limited to Standard of Conduct No. 4, the following: a. Utility-Owned Generation facilities; b.

CalCCA has protested PG&E's application, raising this specific issue within that protest.⁴⁹ CalCCA's reviewing representatives are in the process of investigating the causes of the capacity shortfalls in the Northern California market in the months the Commission cites in the Draft Resolution. That analysis is in its early stages because PG&E did not file its application until February 28, 2023. However, CalCCA's reviewing representatives have noted at least some oddities in PG&E's 2022 RA sales framework that warrant further investigation.

Thus, the Commission's decision to lay the blame of this deficiency at the feet of these two CCAs is, at the very least, premature since the Commission's own process to answer some of the questions underlying the Commission's conclusions have not yet been completed (and, really, have just started). CalCCA, therefore, has had no ability to access the data necessary to refute the Commission's allegation, let alone been provided any opportunity to present an evidence-based case that the Commission has erred in reaching some of the key conclusions that form the basis of the Draft Resolution. Or worse, that the investigation shows the lack of RA capacity in the market is attributable to PG&E's actions, and that the Resolution's conclusions have no foundation in fact.

4. The Draft Resolution Discriminates in the Application of Enforcement for RA Non-Compliance in Violation of Public Utilities Code Section 380(e)

Public Utilities Code Section 380(e) requires the Commission to apply its RA program rules even-handedly. Each LSE must be subject to the same RA program requirements. Similarly, "[t]he commission shall implement and enforce the resource adequacy requirements established in accordance with this section in a nondiscriminatory manner."⁵⁰ The Draft Resolution results in discriminatory enforcement of its RA program requirements.

As explained in Section 1.a., the Draft Resolution is effectively an enforcement action for CCA's RA program deficiencies. The "cure" for the RA program failures in the Draft Resolution is to intentionally delay a CCA's ability to expand. However, that cure cannot neatly be applied to IOUs or ESPs. IOU service territories do not expand, and they are required under their grant of a franchise to serve any new customer who requests service. The mechanism also cannot be applied to IOUs as central procurement entities for their RA procurement deficiencies.

The mechanism is also ill-suited as a penalty for ESPs. The Commission in 2020 recommended against the expansion of the Direct Access program at that time.⁵¹ Consequently, the scope of existing ESP customers cannot legally be expanded. Because this enforcement

Qualifying Facilities (QF) Contracts; and c. Non-QF Contracts. If not, what adjustments, if any, should be made to account for imprudently managed or administered resources?").

⁴⁹ A.23-02-018, *California Community Choice Association's Protest to the Application of Pacific Gas and Electric Company* (Apr. 3, 2023).

⁵⁰ Public Utilities Code § 380(e).

⁵¹ See generally D.21-06-033, *Decision Recommending Against Further Direct Access Expansion*, R.19-03-009 (June 24, 2021).

action would have little or no effect for ESPs or IOUs failing to meet their RA requirements, the Draft Resolution violates Public Utilities Code Section 366.2(c)(8)'s requirement that the Commission apply RA enforcement "in a nondiscriminatory manner."

5. The Commission's Failure to Consider the Environmental and Social Justice Impacts of the Draft Resolution is Inconsistent with Its Own Recommendations and Goals

The Draft Resolution fails to consider the significant impact of the delay of CCA expansion on Environmental and Social Justice (ESJ) Communities, including those in the City of Stockton which seeks to receive expanded service from EBCE.⁵² The Commission commits in the ESJ Plan to "ensur[e] the clean energy transition does not unduly increase rate burdens on lower income communities nor increase existing disparities between lower-income communities and others."⁵³ The Commission's Enforcement Policy, adopted in Resolution M-4846 and providing "guiding principles on enforcement approaches," also specifically requires the Commission to:

Promote enforcement of all statutes within its jurisdictions in a manner that ensures the fair treatment of people of all races, cultures, and income levels, including minority and low-income populations in the state. This includes tailoring enforcement responses to address the needs of vulnerable and disadvantaged communities.⁵⁴

EBCE's expansion request is for the City of Stockton, which passed its ordinance for EBCE to provide CCA service within its city. Much if not all of the City of Stockton is designated as a 2022 Disadvantaged Community (DAC) under the California Environmental Protection Agency's CalEnviroScreen 4.0.⁵⁵ This designation is based on "geographic, socioeconomic, public health, and environmental hazard criteria" and is widely used by the Commission to identify ESJ communities.⁵⁶ Despite the ESJ Plan stating that the Commission will place ESJ issues, as "a priority in all actions the CPUC takes" including "implementation processes included in . . .

⁵² CPUC Environmental & Social Justice Action Plan (ESJ Plan), Version 2.0 (Apr. 7, 2022), located at: <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/news-and-outreach/documents/news-office/key-issues/esj/esj-action-plan-v2jw.pdf>.

⁵³ ESJ Plan at 4.

⁵⁴ Resolution M-4846, *Resolution Adopting Commission Enforcement Policy* (Nov. 5, 2020), Attachment at 4, located at: <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M348/K036/348036813.pdf>.

⁵⁵ See CalEPA website, SB 535 Disadvantaged Communities, Final Designation of Disadvantaged Communities (May 2022), located at: <https://oehha.ca.gov/calenviroscreen/sb535>.

⁵⁶ See ESJ Plan at 10 ("Many of the CPUC's energy-related programs use the CalEnviroScreen tool . . . as means of focusing efforts and prioritizing investment in communities disproportionately affected by air pollution and facing socioeconomic burdens").

resolutions,”⁵⁷ the Draft Resolution entirely fails to analyze the impact of the delayed expansion on Stockton customers and does not mention the DAC designation of the community. In fact, the delayed expansion will prevent Stockton residents the choice to secure their energy from their local CCA, a choice that 11 million Californians have already exercised, enabling their communities to more closely influence the procurement strategies in pursuit of local goals.⁵⁸ If the Commission is truly committed to its ESJ Plan, it should be considering the impact of every decision on ESJ communities, including Stockton.

CONCLUSION

CalCCA appreciates the Commission’s thoughtful and careful consideration of these comments.

Respectfully,

CALIFORNIA COMMUNITY CHOICE
ASSOCIATION



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⁵⁷ ESJ Plan at 23.

⁵⁸ See Stocktonia, [“City Council Votes to Say Goodbye to PG&E as Stockton’s Main Power Source”](#) (Sept. 23, 2022) (describing the City of Stockton City Council’s unanimous adoption of a resolution to join a CCA, and quoting the City’s general manager as stating that the move from PG&E to a CCA will result in rate reductions, environmental benefits, and more local control over the city’s energy).

**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 THE
RULING OF THE ASSIGNED ADMINISTRATIVE LAW JUDGE ENTERING STAFF
PROPOSAL INTO THE RECORD AND NOTICING PUBLIC WORKSHOPS**

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April 18, 2023

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SUMMARY OF RECOMMENDATIONS

- The California Community Choice Association (CalCCA) supports Energy Division’s Option 3: mutually agreed upon assignment clauses with re-entry fee credits. Any form of contract assignability must be voluntary for the load-serving entity (LSE) to avoid the inability to enforce contract assignments in bankruptcy and the adverse impacts forced contract assignments could have on LSE contract negotiations;
- CalCCA generally supports the California Public Utilities Commission’s (Commission’s) financial monitoring proposal with modifications, including:
 - The Commission should require the community choice aggregator (CCA) who triggered financial reporting to have an initial consultation with Energy Division to explain the reasoning behind their trigger. If after the initial consultation, the CCA can demonstrate that its triggering event was not indicative of poor financial health, then the Commission would not require additional financial reporting;
 - The Commission must define criteria that, once met, would allow a CCA to stop financial reporting;
 - The Commission should modify the fourth trigger in the following ways. First, modify the fourth trigger to incorporate the following language: “Event of Default with respect to a buyer’s payment obligations under a procurement contract required to meet Resource Adequacy requirements, provided that a CCA is entitled to any applicable cure periods under such procurement contract.” Second, add a fifth trigger as follows: “Failure to pay a CAISO scheduling coordinator.”
 - The Commission must clarify how Days Liquidity on Hand (DLOH) and Debt Service Coverage Ratios will be calculated. See recommended calculations in Section II.B; and
 - The Commission should modify Energy Division’s proposal to make it explicit that (1) an event that triggers LSE financial reporting and (2) information submitted by a CCA pursuant to its financial reporting requirement is confidential from the Provider of Last Resort (POLR).
- CalCCA does not support the concept of an insurance pool as designed by Pacific Gas and Electric Company (PG&E). If the Commission does consider an insurance pool, then Energy Division Staff’s proposal correctly defers this consideration to Phase 2;
- CalCCA supports a ramping period for the first financial security requirement (FSR) postings after the Phase 1 final decision and a ramping period for new CCAs and recommends the ramping period cover the CCA’s first two FSR postings after the final decision or its first two postings as a new CCA;
- CalCCA supports offering a discount to the FSR amount for LSEs that demonstrate they have a low risk of failure, but recommends important modifications to the Energy

SUMMARY OF RECOMMENDATIONS continued

Division Staff Proposal, including:

- The Commission should modify the hedging requirement to allow LSEs to demonstrate all types of hedges the investor-owned utilities (IOUs) are allowed to use in their bundled procurement plans, at minimum;
 - The Commission should strike the requirement that the LSEs have substantially met their Resource Adequacy (RA) and Integrated Resource Plan (IRP) requirements given RA and IRP capacity market tightness; and
 - The Commission should clarify how it would calculate the FSR “assuming winter market conditions” if a CCA qualifies for the discount or consider using the lower of the current FSR and the last FSR instead.
- The Commission should prioritize updates to the FSR that improve its accuracy;
 - CalCCA continues to oppose the supplemental PG&E proposal that would require postings to reflect two months of POLR service;
 - CalCCA does not support deducting revenues associated with the Power Charge Indifference Adjustment (PCIA) cost responsibility of returned customers without also accounting for the hedge value of the PCIA and Cost Allocation Mechanism (CAM) fleet; and
 - The Commission should not remove the negative procurement cost offset but if it does, it must not use PG&E’s current administrative fee.
-

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R.21-03-011

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE
RULING OF THE ASSIGNED ADMINISTRATIVE LAW JUDGE ENTERING STAFF
PROPOSAL INTO THE RECORD AND NOTICING PUBLIC WORKSHOPS**

The California Community Choice Association¹ (CalCCA) submits these Comments in response to the *Ruling of the Assigned Administrative Law Judge Entering Staff Proposal Into The Record and Noticing Public Workshop*,² *E-Mail Ruling Granting Request to Reschedule Workshop and Extend the Deadline For Filing Comments*,³ and *E-Mail Ruling Granting Request to Reschedule Workshop and Extend the Deadline For Filing Comments*.⁴

¹ California Community Choice Association represents the interests of 24 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, Energy For Palmdale's Independent Choice, Lancaster Choice Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

² *Ruling of the Assigned Administrative Law Judge Entering Staff Proposal Into the Record and Noticing Public Workshops*, Rulemaking (R.) 21-03-011 (Jan. 6, 2023) (Ruling): <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M500/K761/500761891.PDF>.

³ *E-Mail Ruling Granting Request to Reschedule Workshop and Extend the Deadline For Filing Comments*, R.21-03-011 (Feb. 27, 2023): <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M502/K757/502757266.PDF>.

⁴ *E-Mail Ruling Granting Request to Reschedule Workshop and Extend the Deadline For Filing Comments*, R.21-03-011 (March 17, 2023): <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M503/K824/503824337.PDF>.

I. INTRODUCTION

The *Energy Division Staff Analysis and Proposal for Phase 1 Issues in the Provider of Last Resort [POLR] Proceeding* (Energy Division Staff Proposal) puts forth a set of proposals to address continuity of service, financial monitoring, cost recovery, and the load-serving entity (LSE) deregistration.⁵ CalCCA supports many of the elements included in the Energy Division Staff Proposal and proposes a number of modifications to enhance these elements. The comments in sections II.A through II.D make the following recommendations to the Energy Division Staff Proposal:

- CalCCA supports Energy Division’s Option 3: mutually agreed upon assignment clauses with re-entry fee credits. Any form of contract assignability must be voluntary for the LSE to avoid the inability to enforce contract assignments in bankruptcy and the adverse impacts forced contract assignments could have on LSE contract negotiations;
- CalCCA generally supports the California Public Utilities Commission’s (Commission) financial monitoring proposal with modifications, including:
 - The Commission should require the community choice aggregator (CCA) who triggered financial reporting to have an initial consultation with Energy Division to explain the reasoning behind their trigger. If after the initial consultation, the CCA can demonstrate that its triggering event was not indicative of poor financial health, then the Commission would not require additional financial reporting;
 - The Commission must define criteria that, once met, would allow a CCA to stop financial reporting;
 - The Commission should modify the fourth trigger in the following ways. First, modify the fourth trigger to incorporate the following language: “Event of Default with respect to a buyer’s payment obligations under a procurement contract required to meet Resource Adequacy requirements, provided that a CCA is entitled to any applicable cure periods under such procurement contract.” Second, add a fifth trigger as follows: “Failure to pay a CAISO scheduling coordinator.”;

⁵ *Energy Division Staff Analysis and Proposal for Phase 1 Issues in the Provider of Last Resort Proceeding*, R.21-03-011 (Jan.6, 2023): <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M500/K762/500762116.PDF>.

- The Commission must clarify how Days Liquidity on Hand (DLOH) and Debt Service Coverage Ratios will be calculated. See recommended calculations in section II.B; and
- The Commission should modify Energy Division’s proposal to make it explicit that (1) an event that triggers LSE financial reporting and (2) information submitted by a CCA pursuant to its financial reporting requirement is confidential from the Provider of Last Resort (POLR).
- CalCCA does not support the concept of an insurance pool as designed by Pacific Gas and Electric Company (PG&E). If the Commission does consider an insurance pool, then Energy Division Staff’s proposal correctly defers this consideration to Phase 2;
- CalCCA supports a ramping period for the first financial security requirement (FSR) postings after the Phase 1 final decision and a ramping period for new CCAs and recommends the ramping period cover the CCA’s first two FSR postings after the final decision or its first two postings as a new CCA; and
- CalCCA supports offering a discount to the FSR amount for LSEs that demonstrate they have a low risk of failure, but recommends important modifications to the Energy Division Staff Proposal, including:
 - The Commission should modify the hedging requirement to allow LSEs to demonstrate all types of hedges the investor-owned utilities (IOUs) are allowed to use in their bundled procurement plans, at minimum;
 - The Commission should strike the requirement that the LSEs have substantially met their Resource Adequacy (RA) and Integrated Resource Plan (IRP) requirements given RA and IRP capacity market tightness; and
 - The Commission should clarify how it would calculate the FSR “assuming winter market conditions” if a CCA qualifies for the discount or consider using the lower of the current FSR and the last FSR instead.

Additionally, CalCCA urges the Commission to view the example FSR calculations presented at the April 4, 2023 workshop in the context of the policy rationale with which they were proposed, rather than the numbers they produce. Because the final FSR posting amounts will depend heavily on certain inputs to the calculation, select examples cannot fully demonstrate the outcome of each change. Therefore, it is important to focus FSR calculation modifications on improving accuracy by reflecting actual costs and revenues the POLR can expect upon customer

return and accounting for the probability of a return occurring. The comments in section II.E below make the following recommendations on the example FSR calculations:

- The Commission should prioritize updates to the FSR that improve its accuracy;
- CalCCA continues to oppose the supplemental PG&E proposal that would require postings to reflect two months of POLR service;
- CalCCA does not support deducting revenues associated with the Power Charge Indifference Adjustment (PCIA) cost responsibility of returned customers without also accounting for the hedge value of the PCIA and Cost Allocation Mechanism (CAM) fleet; and
- The Commission should not remove the negative procurement cost offset but if it does, it must not use PG&E's current administrative fee.

CalCCA appreciates the proposal put forth by Energy Division Staff that, with some modifications described herein, will result in an effective POLR framework and the opportunity to explore FSR calculation modifications through the examples presented at the workshop.

II. RESPONSES TO QUESTIONS IN THE RULING

A. Continuity of Service

1. **Do parties support, or support with modifications, the four objectives Staff identify as needing to be considered to ensure continuity of service? (See Staff Proposal at 3-4).**

Energy Division Staff identifies the following four objectives to consider for the POLR framework in order to ensure continuity of service:

1. Minimizes the risk of the POLR's insolvency by avoiding exposure to peak market prices in the six months following the customers' return;
2. Minimizes the risk of the CCAs becoming insolvent;
3. Protects returning customers from high reentry fees; and
4. Does not cause cost shifting to bundled customers.⁶

⁶ Energy Division Staff Proposal at 4.

The Commission should modify the fourth objective to say: “Does not cause cost shifting among customers.” The Commission must avoid cost shifts between all customers, both bundled and unbundled, for a workable POLR framework. With this modification, CalCCA generally supports the four objectives identified by Energy Division Staff.

- 2. Do parties support Staff’s proposed schedule under “orderly deregistration,” or propose a different schedule? (See Staff Proposal at 4-6.) Would setting a window for orderly deregistration mitigate the financial risk to the POLR of high market price exposure? Why or why not?**

Energy Division Staff’s proposed schedule appears to set a reasonable timeline for orderly deregistration that would likely limit re-entry fees.

- 3. Do parties support, or support with modifications, any of the options provided by Staff concerning resource assignment clauses? Do parties agree with Staff that Option 3 appears to be the most feasible? (See Staff Proposal at 5-8.)**

CalCCA supports Energy Division’s Option 3: mutually agreed upon assignment clauses with re-entry fee credits. Under this option, “if during the deregistration planning process, the LSE, and seller agree to assign a contract to the POLR, and the POLR agrees to assume the contract, the amount of the resource contracted for can be used to offset the reentry fee.”⁷ Option 3 is the most feasible because it is voluntary. Any form of contract assignability must be voluntary for the LSE to avoid the concerns raised by CalCCA and the IOUs in previous comments including the inability to enforce contract assignments in bankruptcy and the adverse impacts forced contract assignments could have on LSE contract negotiations.

During the workshop, CalCCA requested clarification on how the Commission would recalculate costs for the re-entry fee in the event of contract reassignment and (1) the contract price is higher the benchmark and (2) the market price is higher than the benchmark. For

⁷ *Id.* at 8.

example, assume the benchmark is \$5/kW-month, the contract is \$8/kW-month, and the market price for an RA contract is \$12/kW-month. The Commission should clarify the proposal such that in these cases, the Commission should only adjust the re-entry when the contract price is no higher than the benchmark price. This is because the CCA should be indifferent to the assignment of the contract. If the CCA knew that any contract whose price was higher than the benchmark would result in them paying a higher re-entry fee, they would be incented to not enter into assignment provisions of the contract. In the case depicted in this paragraph, the POLR would rather execute an assignment of a contract at \$8/ kilowatt (kW) -month rather than buy at \$12/kW-month which is in the interest of customers. However, if the fact that the \$8/kW-month contract is above the benchmark would result in the CCA seeing a higher re-entry fee than had they not assigned the contract, they will have an incentive to not assign the contract. This would be detrimental to the POLR who will not have access to the lower cost resources and customers that will pay for the higher cost resource.

4. Can contract assignment clauses support the POLR in retaining resources needed to serve load and limit cost exposure? If so, should they be used to offset the cost of FSRs and/or reentry fees? Why or why not?

Contract assignment clauses can limit cost exposure by reducing the amount of procurement the POLR would need to conduct at market prices at the time of customer return. Therefore, if the LSE, seller, and POLR mutually agree to a contract reassignment, the reassigned contracts should offset the reentry fee, with the clarifications described in response to question C above in which the Commission adjusts the re-entry only when the contract price is no higher than the benchmark price.

CalCCA agrees with Energy Division that it does not seem feasible for the assigned contracts to offset the FSR. This is because it would be unknown at the time of the FSR

calculation whether or not the POLR would take assignment of an LSE's contracts and what the benchmark price will be at that time the LSE returns customers and the POLR does procurement. For this reason, it makes sense to use assigned contracts to offset the re-entry fee only.

B. Financial Monitoring

- 1. Do parties support, or support with modifications, Staff's proposed list of conditions that would trigger financial risk monitoring reporting requirements? (See Staff Proposal at 8-9). If one or more of the conditions should be modified, please explain how and why, being as detailed as possible.**

CalCCA generally supports Energy Division Staff's proposed list of conditions that would trigger financial reporting. However, the proposal must be modified in three ways to ensure CCAs are not required to continually report their financial information when there is no present risk of failure or default.

First, after submitting the confidential letter to the Director of Energy Division and before requiring the up to once per month meeting to provide the CCA's financial information, the Commission should require the CCA who triggered financial reporting to have an initial consultation with Energy Division to explain the reasoning behind their trigger. This initial consultation would include the CCA providing information regarding any counterbalancing factors and/or projected timelines to meet target levels. If after the initial consultation, the CCA can demonstrate that its triggering event was not indicative of poor financial health, then the Commission would not require additional financial reporting. The Commission should adopt this approach because not all situations leading to a CCA hitting one of the triggers are indicative of poor financial health that would require continual monthly meetings and financial reporting.

Second, the Commission must define criteria that, once met, would allow a CCA to stop financial reporting. These criteria should allow the CCA to demonstrate that it has corrected the

financial conditions that initially caused it to be required to report its financials. CalCCA recommends the following criteria, meant to mirror the criteria that would trigger reporting:⁸

- DLOH of 45 days or more or Debt Service Coverage Ratio 1.0 or above;
- Cash reserves of five percent of annual expenses or above;
- Resolving or replacing any RA contract defaults for the immediate RA compliance year (e.g. either by paying the counterparty or by procuring sufficient RA contracts to meet its replace the defaulted contract) or resolving any non-payments to the California Independent System Operator Corporation (CAISO) scheduling coordinator; or
- Emerging from insolvency/bankruptcy.

CalCCA recommends the Commission require CCAs to evaluate the metrics that would trigger financial reporting and trigger ending financial reporting on a monthly basis to avoid the need for the CCA to report, and the Commission to monitor, on a continuous basis.

Third, the Commission should modify the fourth trigger from “Default on procurement contract required to meet Resource Adequacy requirements or to the CAISO scheduling coordinator due to non-payment” as follows. First, modify the fourth trigger to incorporate the following language: “Event of Default with respect to a buyer’s payment obligations under a procurement contract required to meet Resource Adequacy requirements, provided that a CCA is entitled to any applicable cure periods under such procurement contract.” Second, add a fifth trigger as follows: “Failure to pay a CAISO scheduling coordinator.” CalCCA recommends use of the term “Event of Default” because it is a standard defined term in RA contracts that has written notice requirements and that can result in contract termination if not cured. The term “default” is typically not defined in RA contracts and will result in too much uncertainty for the Commission and LSEs about when the trigger has in fact occurred.

⁸ Given the time it takes for the rating agencies to modify credit ratings, CalCCA recommends that if a CCA receives a downgrade below investment grade, it not be required to continue to report once the other four other criteria are met.

In addition to the three modifications above, CalCCA requests the Commission make the following clarifications relative to the “Downgrade below investment grade credit rating” trigger. The Commission should clarify that it would not require LSEs without a credit rating to report – it would only require reporting if a rated LSE goes from an investment grade rating to a non-investment grade rating. This clarification is necessary to avoid overly burdening CCAs without credit ratings by continually requiring them to report until they get a credit rating, even if all their other financial information points to good financial health. For CCAs that share jurisdiction with a City, the credit rating of the City should apply to the CCA itself for the financial monitoring requirements. This is the methodology the CAISO uses for a CCA sharing a jurisdiction with a City when it evaluates credit ratings for its purposes.

Finally, the Commission must clarify how DLOH and Debt Service Coverage Ratios will be calculated. CalCCA recommends the following:

Days Liquidity on Hand:

- Numerator: CCA’s available unrestricted cash and investments and eligible unused bank LOCs and capacity under commercial paper programs, multiplied by 365
- Denominator: CCA’s annual operating and maintenance expenses, excluding depreciation and amortization

Adjusted Debt Service Ratio:

- Numerator: Annual recurring revenue plus interest income plus withdrawals from a Rate Stabilization Fund; minus recurring annual cash operating expenses and General Fund Transfers
 - Recurring revenue and recurring expenses exclude special, one-time items
 - Annual operating expenses excluding depreciation and amortization expenses
- Denominator: Aggregate annual debt service (principal, interest, and fees)

2. What rating is considered “investment grade”?

Per the three ratings agencies, investment-grade ratings are Baa3 or BBB- and above.⁹

This is also consistent with what the CAISO considers investment-grade for its purposes of providing unsecured credit.¹⁰

3. Do parties support, or support with modifications, Staff’s proposed financial risk monitoring reporting requirements? (See Staff Proposal at 9.) If one or more of the risk monitoring reporting requirements should be modified, please explain how and why, being as detailed as possible.

CalCCA generally supports Energy Division Staff’s proposed financial risk monitoring reporting requirements, subject to the modifications and clarifications outlined in response to question B.1. The proposal must be modified to add an initial consultation with Energy Division between the trigger and the reporting and to add criteria that would allow a CCA’s financial reporting requirements to end.

Additionally, in its proposal, Energy Division “considers these reporting requirements, including the initial notification letter, to necessitate confidential treatment to protect the CCA’s market position in securing future procurement.” CalCCA strongly agrees. Energy Division must keep an LSE triggering financial reporting and the reported information confidential – *including from the POLR* – given the POLR is also a market participant and an entity triggering financial reporting will not mean the entity will return load to the POLR in all cases. The Commission should modify Energy Division’s proposal to make it explicit that (1) an event that triggers LSE

⁹ S&P Global at 9: https://www.spglobal.com/ratings/division/assets/pdfs/guide_to_credit_rating_essentials_digital.pdf.

Moody’s: https://www.moody.com/sites/products/productattachments/ap075378_1_1408_ki.pdf;

Fitch: <https://www.fitchratings.com/products/rating-definitions#about-rating-definitions>.

¹⁰ CAISO Business Practice Manual for Credit Management and Market Clearing at 39: https://bpmcm.caiso.com/BPM%20Document%20Library/Credit%20Management%20and%20Market%20Clearing/BPM_for_CreditManagmentandMarketClearing_V14_Clean.doc.

financial reporting and (2) information submitted by a CCA pursuant to its financial reporting requirement is confidential from the POLR. While the Commission may need to inform the POLR of the potential to receive returned load, the Commission must do so without identifying the entity that may return load. Doing so would provide the POLR, in this case the IOU, with information about a potential counterparty that is not otherwise available to the market.

4. How should the Commission enforce the financial reporting requirements and ensure timely disclosure if triggered?

Rule 1.1 of the Commission's Rules of Practice and Procedure prohibits entities doing business with the Commission from misleading the Commission. Rule 1.1 states:

Any person who signs a pleading or brief, enters an appearance, offers testimony at a hearing, or transacts business with the Commission, by such act represents that he or she is authorized to do so and agrees to comply with the laws of this State; to maintain the respect due to the Commission, members of the Commission and its Administrative Law Judges; and never to mislead the Commission or its staff by an artifice or false statement of fact or law.¹¹

This rule would cover the financial reporting requirements and therefore no other form of enforcement is necessary to ensure LSEs timely disclose when they have hit a trigger. As described in section B.1, the Commission should require CCAs to evaluate the metrics that would trigger financial reporting and trigger ending financial reporting on a monthly basis, and Rule 1.1 would require timely disclosure after each monthly evaluation.

¹¹ <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/administrative-law-judge-division/documents/rules-of-practice-and-procedure-may-2021.pdf> (emphasis added).

C. Cost Recovery

- 1. Should Phase 2 of this proceeding further examine the Commission's authority and options for approval and implementation of an insurance pool? Is development of an insurance pool reasonable and necessary? If so, are the conditions identified by Staff in Attachment A sufficient, or should additional/different conditions be considered as part of Phase 2 of the proceeding? (See Staff Proposal at 10-11.)**

CalCCA does not support the concept of an insurance pool as designed by PG&E. An insurance pool is unnecessary, and the Commission should instead focus its efforts on ensuring an accurate FSR calculation. If the Commission does consider an insurance pool, then Energy Division Staff's proposal correctly defers this consideration to Phase 2.

CalCCA agrees the conditions in the Energy Division Staff proposal would need to be addressed before adopting an insurance pool.¹²

- 2. Do parties support Staff's proposal to provide a ramping period for FSRs? (See Staff Proposal at 11-12.) If so, please comment upon how such a ramping period should be designed.**

CalCCA supports a ramping period for the first FSR postings after the Phase 1 final decision and a ramping period for new CCAs. The Commission should design the ramping period such that the ramping period covers the CCA's first two FSR postings after the final decision or its first two postings as a new CCA. This would ensure the ramping period covers at least one summer FSR posting, which is more likely to require a larger posting amount. During the ramping period, the CCA should be required to post half the calculated amount or the minimum, whichever is greater.

¹² Energy Division Staff Proposal at 11-12.

3. Do parties support, or support with modifications, Staff’s proposal to calculate the FSR amount based on winter market conditions, or otherwise offer a discount to the calculated reentry fees for Community Choice Aggregators that demonstrate adequate hedging contracts and are not considered to be at financial risk? Are the proposed risk mitigation measures reasonable?

CalCCA supports offering a discount to the FSR amount for LSEs that demonstrate they have a low risk of failure. Energy Division’s proposal as written, however, contains qualifications that are overly restrictive considering (1) the number of effective hedging mechanisms available to LSE and the hedging mechanisms allowed in the IOUs’ bundled procurement plans, and (2) current RA and IRP market conditions. First, Energy Division Staff’s proposal would only allow discounts to LSEs that demonstrate they “hold fixed price contracts with a collateralized counterparty to meet at least 80 percent of their load forecast.”¹³ The Commission should not limit acceptable hedges to fixed-price contracts only. There are many other effective hedging mechanisms LSEs can use to hedge energy price risk, including call option contracts, swaps, and tolling agreements. The Commission should modify this element of Energy Division Staff’s proposal to allow LSEs to demonstrate all types of hedges the IOUs are allowed to use in their bundled procurement plans, at minimum.¹⁴

Second, the Energy Division Staff’s proposal would require that LSEs “have substantially met” month-ahead and year-ahead RA requirements and IRP requirements as a condition to receive the discount.¹⁵ The Commission should strike this condition from the proposal given current RA and IRP market conditions making it difficult, if not impossible for all LSEs to comply with these obligations.

¹³ Energy Division Staff Proposal at 12.

¹⁴ See PG&E Bundled Procurement Plan Appendix A at: https://www.pge.com/pge_global/common/pdfs/about-pge/company-information/regulation/BundledProcurementPlan.pdf, and SCE Bundled Procurement Plan Appendix C.

¹⁵ Energy Division Staff Proposal at 12.

The RA supply available within the CAISO balancing authority area for 2023 through 2026 appears inadequate to meet the RA program compliance requirements. A wide range of factors have contributed to the current circumstances in which there is insufficient RA supply to meet the RA program compliance requirements. These factors include:

- Weather conditions are more extreme, increasing load and reducing generation output;
- Hydro resource availability has declined under drought conditions;
- New resources are delayed due to permitting, interconnection, and supply chain challenges;
- Reduction in Effective Load Carrying Capability values reduced reliance on wind and solar resources to meet RA requirements;
- Increases in Planning Reserve Margins (PRM) to 16 and 17 percent, with a 20-22.5 percent “effective” PRM for IOUs, increased RA requirements;
- The Commission’s definition of “incremental” procurement to meet the effective PRM encouraged IOUs to cannibalize the existing RA resource stack, reducing supply for other LSEs; and
- Unnecessarily restrictive requirements for energy imports under the Commission’s RA program reduced the availability of imports to the Commission-jurisdictional RA market.

The result of these contributing factors is shown in Figure 1 below, in which demand for RA is projected to exceed the available supply through 2025, with only a very minor surplus in 2026.

Figure 1

September NQC	2023	2024	2025	2026
1 CAISO 1-in-2 Load	46,819	47,475	47,987	48,487
2 Reserve Margin (16% in '23, 17% after)	7,491	8,071	8,158	8,243
3 Total RA Demand	54,310	55,546	56,145	56,730
4 2023 NQC List	47,304	47,304	47,304	47,304
5 Event-Based Demand Response	1,090	1,105	1,111	1,111
6 Imports	5,500	5,500	5,500	5,500
7 Estimate of Incremental Authorized Procurement	1,695	6,505	9,725	10,325
8 Thermal Derates from 2023 NQC List	(726)	(726)	(726)	(726)
9 Remove Diablo from Planning	-	-	(2,280)	(2,280)
10 OTC, Retired or Contracted by DWR	-	(3,692)	(3,692)	(3,692)
11 Excess IOU Procurement for Higher Effective PRM	(1,331)	(1,424)	(1,440)	-
12 Retention for Substitution	(619)	(619)	(619)	(619)
13 Total RA Supply	52,913	53,953	54,883	56,922
14 Surplus Supply (Deficit)	(1,397)	(1,593)	(1,262)	192

LSEs procuring RA for 2023 likely experienced even greater levels of market tightness than this analysis suggests because the entire Western region is constrained, reducing the availability of imports to California and risking increased exports of California resources to meet other Western region requirements (e.g., Western Resource Adequacy Program). A detailed description of current RA market conditions including a list of sources used to develop the stack analysis in Figure 1 can be found in Attachment A incorporated herein.

When it comes to IRP compliance, the Commission has acknowledged “...LSEs and developers are facing exogenous factors such as supply chain impacts on availability of raw materials, import investigations with respect to solar panels, tightening of the economy in the face of inflation, increased demand for clean energy resources throughout the west and globally, and other factors that have material impacts on the development of projects.”¹⁶ While LSEs have been able to meet their compliance obligations to date “due to excess procurement by the CCAs and ESPs[,]”¹⁷ the bulk of procurement ordered by the Commission has compliance dates of 2024 and later, so these exogenous factors may still have impacts on LSEs’ abilities to meet their IRP procurement obligations in future years.

Asking LSEs to be compliant with RA requirements and IRP procurement orders to receive an FSR discount may be realistic when there is sufficient excess RA capacity to produce a competitive RA market and when procurement is ordered in a programmatic and predictable manner. At present, however, RA capacity appears inadequate to meet the RA program’s

¹⁶ *Decision Ordering Supplemental Mid-Term Reliability Procurement (2026-2027) and Transmitting Electric Resource Portfolios to California Independent System Operator for 2023-2024 Transmission Planning Process*, R.20-05-003 (Feb. 28, 2023) at 8: <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M502/K956/502956567.PDF>.

¹⁷ *Summary of Compliance with Integrated Resource Planning (IRP) Order D.19-11-016 and Progress Toward Mid Term Reliability (MTR) D.21-06-035 Procurement* (Feb. 2023) at slide 24: <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/d1911016andd21.pdf>.

compliance requirements and exogenous factors are complicating efforts to develop new projects in response to IRP procurement orders that require compliance in a short timeframe. The Commission should therefore modify Energy Division’s proposal to ensure that it is not too limiting in its qualifications for obtaining the discount by striking the requirement that the LSEs have substantially met their RA and IRP requirements.

CalCCA supports the Commission discounting the FSR if the CCA can demonstrate some level of hedging but requires additional clarification to understand the impacts of “assuming winter market conditions” as suggested in the Energy Division Staff Proposal. The Commission should clarify which components of the FSR would be calculated “assuming winter market conditions” if a CCA qualifies for the discount. Currently, the load forecast and energy cost forecast inputs are seasonal. Under Energy Division’s proposal, would the Commission use winter inputs for the load forecast, energy cost forecast, or both? Would these inputs come from the previous FSR update’s inputs or some other source? In addition, CalCCA has proposed the Commission calculate the FSR using seasonal rates and other parties have proposed to make other inputs seasonal, like RA costs. If adopted, would the Commission use winter inputs for these elements as well? Alternatively, the Commission could instead use the lower of the current FSR and the last FSR. This would essentially allow the CCA to post the lower of the most recent summer FSR and most recent winter FSR. Using winter conditions may not always result in a smaller FSR posting if the winter energy price forwards are unusually high, as observed in the example FSR calculations presented by CalCCA and the IOUs at the April 4, 2023 workshop.

4. Do parties support Staff’s position that the cost recovery proposals above should only apply to Community Choice Aggregators, and not Electric Service Providers?

CalCCA has no comments at this time.

5. Do parties support Staff’s proposal to allow the IOUs to establish a balancing account to track adjustments to the reentry fee? (See Staff Proposal at 15.) Why or why not?

CalCCA supports Energy Division’s proposal to allow the IOUs to establish a balancing account to track adjustments to the reentry fee rather than tracking actual costs because the proposal would set the reentry fees and FSRs consistently. The Commission should clarify how it would adjust the reentry fee given its proposal to adjust the re-entry fee when the LSE, POLR, and supplier mutually agree upon contract reassignment clauses, particularly when (1) the contract price is higher the benchmark, and (2) the market price is higher than the benchmark. As recommended in response to question (c), the Commission should clarify the proposal such that in these cases, the Commission should only adjust the re-entry when the contract price is no higher than the benchmark price.

D. Load Serving Entity (LSE) Deregistration Process

2. Do parties agree with Staff’s proposed deregistration checklist (See Staff Proposal at 15-16 and Appendix A)? If one or more items on the checklist should be modified, please explain how and why, being as detailed as possible.

CalCCA has reviewed the checklist and believes it is accurate and complete. CalCCA does not have any modifications or additions.

3. Are any changes necessary to the deregistration checklist to make it consistent with existing Commission requirements? If so, please explain and include references where applicable.

CalCCA is not aware of any Commission requirements that would require changes to the checklist.

E. Example FSR Calculations Workshop

1. Do parties have any comments on the example FSR calculations presented during the April 4, 2023, workshop?

CalCCA provides the following comments in response to the example FSR calculations presented at the April 4, 2023 workshop.¹⁸

The Commission Should Prioritize Updates to the FSR that Improve Its Accuracy

During the workshop, Energy Division staff asked parties to consider how to balance accuracy and administrative simplicity, given many of the sensitivities presented in the examples resulted in the minimum. The Commission should prioritize improvements to the FSR accuracy over administrative simplicity because the results of the FSR calculation are highly dependent on certain inputs that can result in significant swings in FSR postings. For example, the May 2022 semiannual update demonstrated that the FSR calculation is very sensitive to the forecast energy cost component. Southern California Edison Company's (SCE's) Advice Letter 4789-E-A would have resulted in an increase in the total FSR posting for SCE CCAs from approximately \$1.5 million to approximately \$110 million.¹⁹ The example presented during the workshop presents another unique situation with unusually high winter prices that resulted in more postings above the minimum in the winter sensitivities than in the summer sensitivities. To demonstrate a more normal set of circumstances, CalCCA and the IOUs could update their calculators using forward prices from a previous period (e.g., 2018) so that they are more representative of typical conditions. Regardless, it is the policy rationale that should drive the Commission's FSR

¹⁸ As requested by Energy Division Staff during the workshop, CalCCA has attached its workshop presentation as Attachment B to these Comments. A copy of the FSR calculator Excel spreadsheet will be included in the service email of these Comments.

¹⁹ SCE Advice Letter 4789-E-A *Community Choice Aggregator Financial Security Requirement Reports* for May 2022 (May 19, 2022): <https://cpucadviceletters.org/#/documents/documents/8820/preview/>.

calculation modifications, rather than final FSR posting amounts that result from specific examples, because the final FSR posting amounts will depend highly on the calculation's inputs.

When defining accuracy in the context of the FSR calculation, the Commission should aim to (1) reflect in the calculation actual costs and revenues the POLR can expect upon customer return and (2) account for the probability of a return occurring through a mechanism like those in section B of the Energy Division Staff Proposal as modified in section C.3 of these comments. Adopting an inaccurate FSR calculation with the intention of limiting complexity can put a disproportionate amount of risk on CCA customers by unnecessarily taking up liquidity and credit capacity that CCAs could use to support operations during challenging summer periods or to otherwise serve their customers' interests. The Commission must strike the right balance between protecting bundled customers and setting securitization requirements so high that they undermine stable CCA operations. This is best accomplished by ensuring each component of the FSR calculation accurately reflects the costs and revenues the POLR can expect and the probability of return occurring.

CalCCA Continues to Oppose the Supplemental PG&E Proposal that Would Require Postings to Reflect Two Months of POLR Service

PG&E proposes that the minimum FSR amount reflect two months of POLR service rather than \$147,000 because PG&E "requires upfront liquidity to provide reliable service in a short amount of time."²⁰ When evaluating the impacts of PG&E's proposal, the Commission must keep in mind that the example presented in the workshop did not demonstrate its full magnitude. The example presented at the workshop used an LSE that represented roughly 2.5 percent of load in PG&E territory. Even using an LSE with a very small portion of PG&E load, PG&E's proposal would have resulted in a \$38 million final FSR in for the May filing period

²⁰ Joint IOU FSR Workshop Presentation, April 4, 2023.

with a zero percent pricing sensitivity. Currently, roughly one third of the load is served by CCAs in PG&E's service area. Scaling up the results from an example LSE serving 2.5 percent of PG&E's load to the total load being served by CCAs, an estimated \$517 million would need to be posted in total to satisfy PG&E's proposal under the same set of assumptions used in the example. Modifying the FSR calculations in this manner will have substantial impacts on CCAs' liquidity and/or credit capacity and should be avoided given the purpose of the FSR is to provide basic financial security rather than liquidity.

CalCCA continues to oppose PG&E's proposal for the reasons described in its April 15, 2022 Reply Comments²¹ and its August 5, 2022 Reply Comments,²² and continues to recommend instead that the Commission make changes to the existing components of the FSR calculation to improve its accuracy. While the issue driving PG&E's need for liquidity is the immediate CAISO energy costs of serving returning customers, PG&E has not demonstrated (1) that it is incapable of borrowing in the short term to temporarily finance costs until customers are billed or (2) that CAISO market revenues from the IOUs fleet of resources (PCIA and CAM) will be insufficient to cover these costs. As discussed in the workshop, the CAISO charges market participants for load and pays market participants for supply at the same time, meaning as PG&E pays CAISO charges for returning customers it concurrently receives revenues from its PCIA and CAM fleet. If PG&E is still unable to resolve its liquidity concerns considering its ability to borrow and its revenues that it expects to receive from the CAISO market, then the

²¹ *California Community Choice Association's Reply Comments on Administrative Law Judge's Ruling Distributing Workshop Agenda and Providing Questions for Additional Post Workshop Comments*, R.21-3-011 (Apr. 15, 2022), at 4-6.

²² *California Community Choice Association's Reply Comments on Ruling of the Assigned Commissioner and Assigned Administrative Law Judge Requesting Comments on Financial Security Requirements and Reentry Fees, and Modifying the Proceeding Schedule*, R.21-03-011 (Aug. 5, 2022), at 7-8: <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M496/K416/496416748.PDF>.

Commission must immediately commence Phase 2 of this proceeding, where parties will consider the POLR framework with an entity other than the IOU acting as the POLR.

CalCCA Does Not Support Deducting Revenues Associated with the PCIA Cost Responsibility of Returned Customers without also Accounting for the Hedge Value of the PCIA and CAM Fleet

The IOUs propose to deduct revenues associated with the PCIA cost responsibility of the mass involuntarily returning customers from the revenue component of the FSR calculation.²³ If the Commission adopts this proposal, the Commission must also adopt accompanying changes made by CalCCA to account for the hedge value of the PCIA fleet and CAM fleet. CalCCA included these changes in its July 5, 2022 comments.²⁴ These comments explain that the PCIA operates as an energy price “hedge” by reducing price exposure in all price-spike scenarios, including those in which departed customers return to IOU service. The FSR calculation currently relies on a forecast of how much the POLR will need to pay to supply returned customers for six months *assuming completely unhedged positions*. Without an adjustment, the IOUs’ proposal would require returning customers to pay twice for PCIA energy hedge value; once through the FSR/Re-Entry Fee and a second time through ERRA.

Similarly, CAM resources provide an energy price hedge by netting energy market revenues against the cost of the contract. When a customer returns to bundled service, CAM costs and benefits, including offsetting energy revenues, follow the customer, providing the POLR with an additional energy hedge. Therefore, the IOU will not be at risk for the cost of energy associated with the CAM portfolio used to serve the returning customer load.

²³ Joint IOU FSR Workshop Presentation, April 4, 2023.

²⁴ *California Community Choice Association’s Comments on Ruling of the Assigned Commissioner and Assigned Administrative Law Judge Requesting Comments on Financial Security Requirements and Reentry Fees, and Modifying the Proceeding Schedule*, R.21-03-011 (July 5, 2022), at 11-12 (CAM energy) and 16-19 (PCIA energy):
<https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M490/K740/490740399.PDF>.

Adopting the IOUs' proposal to deduct revenues associated with the PCIA cost responsibility of returned customers without CalCCA's proposal will result in an imbalance in accounting for the PCIA and essentially ask returning customers to pay twice for energy they pay for through PCIA and CAM. The Commission must therefore only adopt the IOUs' proposal with the accompanying proposals from CalCCA to account for the hedge values from PCIA and CAM.

The Commission Should Not Remove the Negative Procurement Cost Offset but if It Does, It Must Not Use PG&E's Current Administrative Fee

The IOUs propose to remove the negative procurement cost offset used to offset administrative costs because the IOUs will "incur incremental administration costs irrespective of forecast procurement costs" and to "ensure the FSR minimum is greater of the administrative costs or \$147,000."²⁵ CalCCA continues to oppose removing the negative procurement cost offset from the FSR calculation, as the FSR calculation is the sum of the anticipated energy, RA, RPS, and administrative costs, minus the anticipated revenues.²⁶ If anticipated revenues fully cover the sum of all costs, there is no rational reason to select a single cost element as the basis for an FSR minimum. However, if the Commission does decide to remove the negative procurement cost offset, it must use the average of SCE's and SDG&E's administrative fee as the value used in the FSR calculation, and not rely on PG&E's administrative fee. As described in CalCCA's July 5, 2022 comments, PG&E's administrative fee is significantly higher than the other IOUs' and has not been thoroughly vetted.²⁷ While SCE and SDG&E's administrative

²⁵ Joint IOU FSR Workshop Presentation, April 4, 2023.

²⁶ *California Community Choice Association's Reply Comments on Ruling of the Assigned Commissioner and Assigned Administrative Law Judge Requesting Comments on Financial Security Requirements and Reentry Fees, and Modifying the Proceeding Schedule*, R.21-03-011 (Aug. 5, 2022), at 11-13: <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M496/K416/496416748.PDF>.

²⁷ *California Community Choice Association's Comments on Ruling of the Assigned Commissioner and Assigned Administrative Law Judge Requesting Comments on Financial Security Requirements and Reentry Fees, and Modifying the Proceeding Schedule*, R.21-03-011 (July 5, 2022), at 34-6: <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M490/K740/490740399.PDF>.

costs are roughly \$0.50 per customer service account, PG&E’s administrative costs are \$4.24 per customer service account. PG&E has provided categories of costs and an estimated four minutes per account processing time but has not provided work papers to describe how they arrived at the processing time driving the administrative costs. Given this, the Commission should not net the negative procurement cost offset from the FSR calculation, but if it does, it should not rely on PG&E administrative fees.

2. Parties may also include additional example FSR calculations in comments. Any example calculations should clearly identify the inputs used, and provide a rationale for any inputs that differ from what was presented during the March 7, 2023 workshop.

CalCCA does not have any additional example FSR calculations at this time, as calculations presented at the April 4, 2023 workshop present all of CalCCA’s proposed changes. If the Commission would like to better understand the results of example FSR calculations during times with more typical energy prices, as suggested in response to question E.1, CalCCA can work with the IOUs to coordinate on the data necessary to perform those calculations.

III. CONCLUSION

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

Respectfully submitted,



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

April 18, 2023

**ATTACHMENT A
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE
RULING OF THE ASSIGNED ADMINISTRATIVE LAW JUDGE ENTERING STAFF
PROPOSAL INTO THE RECORD AND NOTICING PUBLIC WORKSHOPS**

**CALIFORNIA'S CONSTRAINED RESOURCE ADEQUACY MARKET:
RATEPAYERS LEFT STANDING IN A GAME OF MUSICAL CHAIRS
Updated March 20, 2023**

CALIFORNIA’S CONSTRAINED RESOURCE ADEQUACY MARKET: RATEPAYERS LEFT STANDING IN A GAME OF MUSICAL CHAIRS

Updated March 20, 2023

1. Introduction

The Resource Adequacy (RA) supply available within the California Independent System Operator (CAISO) balancing area for 2023 appears inadequate to meet the RA program compliance requirements. The “stack” analysis in Figure 1 below, which compares RA requirements with the available RA supply, demonstrates that the margin is razor thin “on paper.”¹ The recent Joint Agency Reliability Planning Assessment by the California Energy Commission (CEC) and California Public Utilities Commission (CPUC), which is based on an hourly analysis of anticipated supply and projected demand, roughly substantiates this conclusion. When the stack analysis is viewed in the context of regulatory dynamics and Western market constraints, however, the razor-thin margin becomes a material supply deficiency.

A wide range of factors have contributed to these conditions:

- Weather conditions are more extreme, increasing load and reducing generation output.
- Hydro resource availability has declined under drought conditions.
- New resources are delayed due to permitting, interconnection, and supply chain challenges.
- The entire Western region is constrained, reducing the availability of imports to California² and risking increased exports of California resources to meet other Western region requirements (*e.g.*, Western Resource Adequacy Program (WRAP)).
- CPUC reduction in effective load carrying capacity values reduced reliance on wind and solar resources to meet RA requirements.
- CPUC’s increase in planning margins (PRMs) to 16%, with a 20-22.5% “effective” PRM for investor-owned utilities (IOUs), increased RA requirements.
- CPUC’s definition of “incremental” procurement to meet the effective PRM encouraged IOUs to cannibalize the existing RA resource stack, reducing supply for other LSEs.
- Unnecessarily restrictive requirements for energy imports under the CPUC’s RA program reduced the availability of imports to the CPUC-jurisdictional RA market.

The RA supply deficiency will prevent collective compliance by CAISO load-serving entities (LSEs) despite their best efforts to procure and willingness to pay exorbitant prices. Some LSEs subject to the CPUC’s RA program were unable to obtain enough supply to comply with their

¹ The stack analysis focuses on the sufficiency of supply to enable load-serving entities to comply with RA program requirements and does not analyze the likely sufficiency of energy to meet Summer 2023 needs.

² Historical RA import data from the CAISO demonstrates that the amount of imports in year-ahead RA showings declined from 5,900 MW in 2020 to 3,600 MW in 2022. RA imports from unspecified declined from 4,300 MW to 1,300 MW over the same period. Historical year-ahead RA data: <http://www.caiso.com/Documents/HistoricalYearAheadResourceAdequacyAggregateData.xlsx>.

year-ahead RA compliance requirements despite numerous formal solicitations and substantial bilateral outreach. Recent experience suggests the problem will only grow in the month-ahead RA compliance process absent a substantial increase in hydro output, imports, or expedited deployment of new resources.

Not all LSEs start the game with the same odds. IOUs hold most “legacy” supplies built prior to the recent growth of community choice aggregation (CCA) and the expansion of Direct Access (DA). As CCA or DA load has departed the IOU portfolio, the IOUs have retained for their remaining bundled load the supply previously procured for the departed load. Consequently, as conditions have changed, the burden of finding new supply to meet requirements has shifted largely to CCA and DA customers. The challenges in getting new steel in the ground thus have had a graver effect on these customers.

Under these conditions, RA program compliance has become a game of musical chairs: some chairs are occupied by the IOUs and some have been grabbed by out-of-state entities, leaving some California LSEs without a chair when the music stops. Until more new resources come online, the race to find a chair in the game will have detrimental consequences for all consumers. The RA shortfall has driven up prices paid by consumers. Sellers are the only market participants who benefit from this pressure.

RA penalties for LSEs unable to secure supply in a deficient market do nothing to get new resources in the ground; they unnecessarily add to customer costs and indirectly increase the cost of supply. Resource development is properly addressed in the CPUC’s Integrated Resource Planning process and procurement mandates.

2. RA Supply/Demand Balance: 2023 RA Stack Analysis

The RA stack analysis in Figure 1 below compares the demand for system RA for peak months in 2023 to the total supply of RA, including RA from resources in the CAISO footprint and estimated RA imports. RA supply is primarily derived from the CAISO’s net qualifying capacity list, while RA demand is the forecasted median load in the CAISO plus a planning reserve margin.

As shown in Figure 1 below, demand for RA exceeds the available supply of RA, even after accounting for imports and expected addition of resources, in three of the four peak summer months. The projected deficit is nearly 1,400 megawatts (MW) in September 2023. The scarcity of supply makes it difficult, if not impossible, for every LSE to meet its RA requirements.

³ <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2019rareport-1.pdf>, at 22.

Figure 1

	Jun	Jul	Aug	Sep
1 CAISO 1-in-2 Load	42,056	45,397	45,922	46,819
2 Reserve Margin (16%)	6,729	7,264	7,347	7,491
3 Total RA Demand	48,786	52,661	53,269	54,310
4 Owned by Calpine	5,874	5,864	5,861	5,867
5 Owned by AES	3,657	3,657	3,655	3,655
6 Owned by NRG	2,321	2,317	2,315	2,322
7 Owned by Other	36,426	36,843	36,124	35,460
8 Event-Based Demand Response	995	1,045	1,077	1,090
9 Imports	5,500	5,500	5,500	5,500
10 Thermal Plant Derate	(726)	(726)	(726)	(726)
11 Excess IOU Resources Above PRM (D.21-12-015)	(794)	(925)	(664)	(206)
12 Supply-Side Emergency Reliability Procure. (D.21-12-015)	(883)	(933)	(824)	(1,125)
13 Retention for Substitution	(619)	(619)	(619)	(619)
14 Total RA Supply	51,751	52,023	51,699	51,218
15 Surplus Supply (Deficit)	2,966	(638)	(1,570)	(3,092)
16 Expected New Resources	-	-	1,695	1,695
17 Surplus Supply (Deficit) with New	2,966	(638)	125	(1,397)

3. Sources and Explanation of the RA Stack

Figure 1 uses both familiar data in assessing RA supply sufficiency and also integrates information not typically considered in a supply analysis. This information, reflected in rows 11 through 13, stems from regulatory changes implemented by the CPUC that had the effect of eroding supply available to other LSEs. The table below documents the sources of data used in Figure 1.

Row(s)	Source
1	CAISO 1-in-2 Load Forecast. Monthly peak demand forecast for a median (1-in-2) weather year from the CPUC. ⁴
2	Planning Reserve Margin per CPUC D.22-06-050. ⁵
4-7	California ISO NQC List. The CAISO lists the net qualifying capacity (NQC) for all resources in the CAISO footprint for 2023. ⁶ We identify the plant owner by matching the resource identification number (resource ID) in the NQC list to the resource ID in the CAISO Master Generating List. ⁷ Three companies (Calpine, AES, and NRG) and their affiliates own nearly 12 GW (over 20%) of NQC.

⁴ CPUC’s 2023 Forecast Summary Tables: <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/ra-2023-forecast-summary-tables.xlsx>.

⁵ D.22-06-050, *Decision Adopting Local Capacity Obligations For 2023 - 2025, Flexible Capacity Obligations For 2023, and Reform Track Framework*, R.21-10-002 (June 23, 2022): <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M488/K540/488540633.PDF>.

⁶ CAISO 2023 NQC List: <https://www.caiso.com/Documents/2023-net-qualifying-capacity-values-for-resource-adequacy-resources.html>.

⁷ CAISO Master Control Area Generating Capability List: oasis.caiso.com.

Row(s)	Source
8	Event-Based Demand Response. Demand response quantities are from the CPUC’s Resource Adequacy Compliance Materials. ⁸ Demand response totals include avoided losses and are from event-based programs at PG&E, SCE, and SDG&E.
9	Imports. Imports reflect the CEC’s assumed RA imports available to the CAISO market. ⁹
10	Thermal Plant Derate. Many thermal generators cannot produce maximum output at certain temperatures, leading to plant derates. For this reason, resource owners may not sell their full NQC as RA capacity. For thermal plants whose NQC is listed as equivalent to their Net Dependable Capacity, we apply a technology-specific thermal derate estimated from historical ambient temperature derates within the CAISO. ¹⁰ Our approach parallels recent CPUC discussions regarding the need to include thermal derates in reliability modeling. ¹¹
11	D.21-12-015 allowed: “excess resources from an IOU’s <i>existing</i> portfolios may be used to meet or supplement these procurement targets up to the upper end of its contingency procurement target.” ¹² Line 11 represents the total of the three IOUs’ excess resources from their portfolios as filed in the IOU 2022 Excess Resources Report. ¹³
12	D.21-12-015 authorized the IOUs to “continue their procurement efforts and endeavor to meet and exceed their respective incremental procurement targets to achieve the range of additional procurement authorized in this decision for months of concern... As noted previously, a combination of RA eligible and non-eligible resources will be used to meet the contingency procurement target range.” ¹⁴ While these resources were intended to be incremental to supply available to LSEs to meet their 16% requirement, a significant amount appears to erode existing supply. ¹⁵ This erosion occurs because many of the resources are qualified to provide RA and, were it not for the IOU procurement, could provide RA to other LSEs to meet their RA compliance requirements. ¹⁶

⁸ 2023-2025 Demand Response Totals: <https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-compliance-materials>.

⁹ Joint Agency Reliability Planning Assessment - SB 846 Quarterly Report and AB 205 Report, at 43: <https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=21-ESR-01>.

¹⁰ Ambient derate data can be found in the CAISO’s daily Curtailed and Non-Operational Generator Prior Trade Date Reports: <http://www.caiso.com/market/Pages/OutageManagement/CurtailedandNonOperationalGenerators.aspx>.

¹¹ ED Staff Proposal for Derating Thermal Power Plants based on Ambient Temperature: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/r21-10-002/4_ed-proposal-for-phase-3-derates.pdf.

¹² D.21-12-015 at 103.

¹³ <https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-compliance-materials>.

¹⁴ D.21-12-015 at 101-102.

¹⁵ The additional resources procured under this authorization are described in the CPUC’s RA materials with additional detailed provided in advice letters filed by the IOUs. 2022 IOU Excess Resource reports: <https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-compliance-materials>.

¹⁶ CalCCA used the amounts in the IOU reports and removed those resources that would not otherwise qualify for RA (e.g., Emergency Load Reduction Program). The resources included in row 12 include firm energy imports, additional RA contracts, tolling agreements, extension of existing contracts that are RA eligible, and contracts for increased output where the efficiency upgrades likely could have been financed by an RA contract with an LSE.

Row(s)	Source
13	Retention for substitution. IOUs are entitled to retain RA beyond their bundled needs for substitution during planned outages. While 2022 data are not yet available, this assessment relies on the 2021 resources retained by IOUs as reported in the 2021 IOU Excess Resource reports. ¹⁷
16	Expected new-build resources online by 8/1/23. Resources mandated by the CPUC pursuant to D.19-11-016 and D.21-06-035 assuming a 40% delay and/or failure rate.

4. Tight Conditions Are Likely to Persist Through 2026

Extending the RA stack for September through 2026, Figure 2 below shows that the tight market conditions continue. The challenge of meeting RA requirements is exacerbated by rising load, increasing planning reserve margins, and retirement or removal from the RA market of resources like Diablo Canyon Power Plant (DCPP) and several once-through cooling plants. Deployment of new capacity to meet the CPUC’s procurement requirements helps, though projects are likely to be delayed at least in the next few years. Though not reflected here, the RA market will undergo a fundamental shift in design, changing to a 24-hour slice of day approach starting in 2025.¹⁸

The sources and assumptions in this extended stack analysis are similar to the 2023 stack in Figure 1, with the following exceptions:

- The load forecast for 2024-26 is based on the CEC’s 2022 Integrated Energy Policy Report Planning scenario;¹⁹
- The planning reserve margins for 2024-2026 increase to 17%;²⁰
- In line with the assumptions of the Joint Agency Reliability Planning Assessment, described in the next section, DCPP is retired in 2025 and the remaining once-through-cooling plants are assumed to be procured by DWR;²¹ and
- Excess IOU procurement for a higher effective PRM continues through 2025.²²

¹⁷ <https://www.cpuc.ca.gov/industries-and-topics/electricalenergy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-compliancematials>.

¹⁸ D.22-06-050 at 128.

¹⁹ CEC’s California Energy Demand 2022 Hourly Forecast for the CAISO region with the Planning Scenario, based on the monthly maximum of the CAISO Managed Net Load: <https://efiling.energy.ca.gov/GetDocument.aspx?tn=248359&DocumentContentId=82768>.

²⁰ D.22-06-050 at 125 requires a 17% PRM for 2024, we assume the same for 2025-26.

²¹ The capacity of once-through-cooling plants at risk of retirement is based on the CAISO’s Announced Retirement and Mothball List: <http://www.aiso.com/planning/Pages/ReliabilityRequirements/Default.aspx>.

²² R.21-10-002, Appendix A, *Energy Division Proposals for Proceeding R.21-10-002* (Jan. 20, 2023), at 7: As part of Proposal 1, Energy Division staff propose to retain the 17% PRM while also extending the effective PRM through 2025 at a level of 3% of the forecasted peak load. <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M501/K407/501407493.PDF>.

Figure 2

September NQC	2023	2024	2025	2026
1 CAISO 1-in-2 Load	46,819	47,475	47,987	48,487
2 Reserve Margin (16% in '23, 17% after)	7,491	8,071	8,158	8,243
3 Total RA Demand	54,310	55,546	56,145	56,730
4 2023 NQC List	47,304	47,304	47,304	47,304
5 Event-Based Demand Response	1,090	1,105	1,111	1,111
6 Imports	5,500	5,500	5,500	5,500
7 Estimate of Incremental Authorized Procurement	1,695	6,505	9,725	10,325
8 Thermal Derates from 2023 NQC List	(726)	(726)	(726)	(726)
9 Remove Diablo from Planning	-	-	(2,280)	(2,280)
10 OTC, Retired or Contracted by DWR	-	(3,692)	(3,692)	(3,692)
11 Excess IOU Procurement for Higher Effective PRM	(1,331)	(1,424)	(1,440)	-
12 Retention for Substitution	(619)	(619)	(619)	(619)
13 Total RA Supply	52,913	53,953	54,883	56,922
14 Surplus Supply (Deficit)	(1,397)	(1,593)	(1,262)	192

5. Results Generally Align with Joint Agency Reliability Assessment

The Joint Agency Reliability Planning Assessment, issued on February 9, 2023, assessed hourly supply sufficiency across each year between 2023-2032. Here we focus on the Joint Agency results during critical hours in the month of September 2023-2026 using their assumption that new resources are based on ordered procurement with a delay rate of 40%. This assessment differs from the CalCCA assessment above because it focuses on hourly supply sufficiency, rather than RA sufficiency for compliance purposes. Consequently, the Joint Agency assessment:

- Projects a higher percentage of completion of new resources by August 1, 2023 (1,750 MW vs. 1,695 MW);
- Uses hourly production of wind and solar on peak demand days, resulting in a contribution of 1,819 MW from wind and solar to meeting demand in Hour 19 of September, compared to the 2,359 MW of wind and solar NQC in the RA stack;
- Uses demand response estimates that may include programs that are not typically used to meet RA requirements;
- Assumes the full contribution of thermal plants are available each hour without accounting for ambient thermal derates associated with high temperatures;
- Does not need to consider the effect of the IOUs’ retention of capacity for substitution, since those resources will be available supply unless they are actually substituted for a resource on outage; and
- Does not need to consider the effect of the IOUs’ incremental “effective” PRM procurement; although the supply may not be available to LSEs to meet their RA requirements, the resources will be a part of the actual supply.

Despite these differences, which tend to present a more positive view of supply, the assessment shows a very tight supply margin, for Hour 19 in September – arguably the most challenging hour to meet. The Joint Agency assessment is summarized below in Figure 3, which was prepared by CalCCA using Joint Agency data.²³

Figure 3

Hour 19 Assessment in the Month of September		2023	2024	2025	2026
1	CAISO 1-in-2 Load	46,827	47,472	47,933	48,424
2	Reserve Margin (16% in '23, 17% after)	7,492	8,070	8,149	8,232
3	Total Hourly Demand	54,319	55,542	56,082	56,656
4	Existing Resources Except Wind and Solar	44,817	44,817	44,817	44,817
5	Supply from Wind	1,810	1,810	1,810	1,810
6	Supply from Solar	9	9	9	9
7	Estimated Completion of CPUC Mandated Procurement	1,750	6,431	10,381	11,755
8	Demand Response	1,274	1,274	1,274	1,274
9	Imports	5,500	5,500	5,500	5,500
10	Remove Diablo from Planning	-	-	(2,280)	(2,280)
11	OTC, Retired or Contracted by DWR	-	(3,757)	(3,757)	(3,757)
12	Total Hourly Supply	55,159	56,084	57,753	59,128
13	Surplus Supply (Deficit)	840	542	1,672	2,472
14	Incremental Demand with 2020 Equivalent Event	3,044	2,611	2,636	2,663
15	Add'l. Incremental Demand with 2022 Equivalent Event	1,639	1,662	1,678	1,695
16	Surplus Supply (Deficit) with Extreme Weather	(3,843)	(3,731)	(2,642)	(1,887)

6. Conclusion

The supply of Resource Adequacy is insufficient to meet 2023 demand. This insufficiency made it impossible for all LSEs to comply with year-ahead requirements, and the insufficiency likely will carry into month-ahead compliance requirements absent a significant increase in hydro RA availability. The only durable solution is to bring new resources online, yet new resources continue to face supply chain, interconnection, and permitting challenges. Until those challenges are met holistically, RA supply will remain tight and prices paid by consumers will remain high.

Five interim actions should be considered.

- 1) Recognize the RA supply insufficiency and its consequences in the CPUC’s next RA decision.

²³ CalCCA created the table from the underlying data used in the Joint Reliability Planning Assessment (<https://efiling.energy.ca.gov/GetDocument.aspx?tn=248714&DocumentContentId=83233>) consistent with a conversation with CEC staff on Jan. 31, 2023.

- 2) Establish a “safety valve,” through a discretionary waiver structure for LSEs left deficient in meeting their requirements despite best efforts, to prevent the exercise of market power by suppliers.
- 3) Increase the likelihood that California LSEs can secure imports for RA compliance by increasing the CPUC-imposed energy market bid cap on imports – currently set at \$0/MWh -- to reduce sellers’ risk of financial loss.
- 4) Prevent erosion of the supply stack available to LSEs to meet their RA requirements by limiting any IOU “effective PRM” procurement to truly incremental, non-RA resources.
- 5) Increase market transparency by providing aggregated compliance data to reveal (a) trends in the categories of resources (e.g., imports, storage) used for compliance and (b) the extent of California resource exports.

**ATTACHMENT B
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE
RULING OF THE ASSIGNED ADMINISTRATIVE LAW JUDGE ENTERING STAFF
PROPOSAL INTO THE RECORD AND NOTICING PUBLIC WORKSHOPS**

**CALCCA PROPOSAL REFRESHER AND SUMMARY OF RESULTS
April 4, 2023**



Comments on April 5, 2023 stakeholder workshop

Initiative: Extended day-ahead market ISO balancing authority area participation rules

Comment period

Apr 05, 2023, 08:00 am - Apr 19, 2023, 05:00 pm

Submitting organizations

California Community Choice Association

California Community Choice Association

Submitted on 04/19/2023, 02:45 pm

Contact

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

1. Please provide a summary of your organization's comments on the April 5, 2023 Extended Day-Ahead Market (EDAM) ISO Balancing Authority Area (BAA) Participation Rules stakeholder workshop discussion:

The California Community Choice Association (CalCCA) appreciates the opportunity to comment on the April 5, 2023 EDAM ISO BAA Participation Rules stakeholder workshop. CalCCA's comments focus on (1) resource sufficiency evaluation (RSE) cost allocation, (2) setting the net export transfer constraint in a manner that preserves capacity dedicated to California during times of system stress, and (3) clarifying the historical wheeling access charge (WAC) revenue recovery proposal.

In summary:

CalCCA supports the initiative's scope and schedule and agrees with the need to complete Track A issues to support day 1 of EDAM go-live. As the discussion evolves, the California Independent System Operator Corporation (CAISO) and stakeholders should consider whether certain Track B elements can be revisited after initial EDAM implementation.

The ideas for Track A on Slide 20 appear to be the right steps to take using existing tools if the CAISO fails advisory RSE. CalCCA supports exploring a CAISO balancing authority areas (BAA) procurement mechanism to cure RSE advisory failures once the options on Slide 20 are exhausted. Any CAISO procurement mechanism should allow for the consideration of the magnitude of the failure, the cost of curing the failure, and the cost of failing the RSE before curing.

CalCCA does not support allocating RSE failure surcharges based upon demand net supply (option three), as many load-serving entities (LSEs) are not their own scheduling coordinators, making it difficult, if not impossible, to tie supply offers to LSEs. Additionally, LSEs are incentivized to bring enough supply to the day-ahead market through both the California Public Utilities Commission (CPUC) and the CAISO Resource Adequacy (RA)

compliance mechanisms.

CalCCA supports the list of conditions for setting the net export transfer constraint included in the CAISO presentation, including Flex Alerts, D+2 Residual Unit Commitment (RUC) infeasibilities, and the RA outlook (Slide 30), as each of these conditions can signal stressed system conditions.

Transfer resource settlement payments should be allocated in a manner that is consistent with how the charges are allocated.

It is unclear at this point how to accurately capture historical WAC revenues given the impacts EDAM will have on schedules and WAC's dependency on the current state of the transmission system.

2. Provide your organization's comments on the proposed EDAM ISO BAA Participation Rules initiative scope and schedule:

CalCCA supports the initiative's scope and schedule and agrees with the need to complete Track A issues to support day 1 of EDAM go-live. As the discussion evolves, the CAISO and stakeholders should consider whether it is necessary to complete Track B policy and take it to the CAISO Board of Governors before EDAM implementation or whether certain Track B elements can be revisited after initial EDAM implementation. Completing the Track B policy after initial EDAM implementation would allow time to see how the Track A policies function before finalizing the Track B policy.

3. Provide your organization's comments on scope item #1 – process to cure advisory resource sufficiency evaluation (RSE) shortfalls:

CalCCA largely supports the proposed objectives for curing advisory RSE shortfalls, including minimizing RSE failures while also minimizing additional BAA costs, curing RSE shortfalls using existing mechanisms, and allocating costs in a manner commensurate with cost causation where feasible (see Slide 18). As discussed in response to question four below, CalCCA has concerns with the discussions around cost allocation, particularly when considering allocating costs dependent upon LSE contracted supply.

The ideas for Track A on Slide 20 appear to be the right steps to take using existing tools if the CAISO fails advisory RSE. These steps could be sequenced so that the more costly measures, such as exceptional dispatch, occur later in the process and those that leverage existing resources under contract occur earlier in the process (like moving forward the bid insertion timeline for RA resources). When issuing market notices to LSEs asking for additional offers, the CAISO should include the size of the deficiency and the LSEs' share of the deficiency so the LSEs know the amount of deficiency charges that could be allocated to them if not cured. This information should be provided confidentially to each LSE so as not to reveal market-sensitive information as LSEs attempt to cure.

CalCCA supports exploring a CAISO BAA procurement mechanism to cure RSE advisory failures once the options on Slide 20 are exhausted. Any CAISO procurement mechanism should allow for the consideration of the magnitude of the failure, the cost of curing the failure, and the cost of failing the RSE before curing. Any resource eligible to count towards the RSE should be eligible to cure RSE advisory shortfalls.

A CAISO BAA procurement mechanism could be modeled off the CAISO's existing Capacity Procurement Mechanism (CPM) used for RA deficiencies, significant events, and exceptional dispatches. CPMs typically have a 30-day minimum term, but as the CAISO notes on Slide 21, a one-day term may fit best with the timing of the RSE given the RSE is re-run daily to capture loads,

resources, and uncertainty for each day. The CAISO should explore whether or not a one-day term would be supported by the Federal Energy Regulatory Commission (FERC), given it would divert from previous FERC orders on the term of the existing CPM mechanism. Offers into the CAISO's procurement mechanism should be capped, but the appropriate cap is dependent upon the term of the procurement.

4. Provide your organization's comments on scope item #2 – process to allocate RSE failure surcharges and revenues:

The CAISO presents three options for allocating RSE failure surcharges and revenues (Slide 25). Option one would allocate surcharges and revenues pro-rata to SCs based upon metered demand. Option two would allocate surcharges to generators who did not comply with their must-offer obligations and revenues to generators who did comply with their must-offer obligations. Option three would allocate charges to SCs based on metered demand net of supply and revenues to SCs based on supply net of metered demand.

CalCCA understands the long-term objective of incenting market participants to bring enough supply to the day-ahead market to pass the RSE by allocating costs and revenues in a manner that follows cost causation principles. However, CalCCA does not support option three because it would be extremely difficult to tie a resource's schedule to a particular LSE, which appears to be the intent of the option. LSEs do not have to be the scheduling coordinator for their resources. Since that is the case, there is not a one-for-one relationship between the schedule of a resource and the LSE for which it is serving. Even where an LSE is the scheduling coordinator for a resource, there is no guarantee that the resource being scheduled is to serve that LSE's load. The LSE may have sold the output associated with that resource to another LSE. The only way to realistically allocate charges based on metered demand net of supply to understand the contractual obligation between LSEs and resources, the schedule alone does not provide this information.

Additionally, implementing option three on top of the RA program compliance mechanisms already in place would result in duplicative charges on LSEs who have already paid for their deficiencies through the RA program. LSEs are incentivized to bring enough supply to the day-ahead market through both CPUC and CAISO RA compliance mechanisms. The RA program incents upfront compliance through a robust penalty structure at the CPUC. LSEs face tiered penalties increasing in price based upon the number of deficiencies the LSEs have. If LSEs are short on their RA requirements, in addition to paying the CPUC penalties, the CAISO can backstop through its CPM to fill the deficiency and allocate costs first to deficient LSEs. Therefore, LSEs will either (1) collectively meet their RA obligations, obviating the need for CAISO backstop, or (2) receive costs of CAISO backstop allocated to them if they are the cause of a deficiency. After CAISO backstop for RA deficiencies occurs, LSEs' obligations to bring supply to the day-ahead market should be considered fulfilled, and it is up to the supplier to ensure the resource is available and offered into the day-ahead market consistent with its must-offer obligation to pass the RSE. If a resource does not comply with its must-offer obligation, the resource is assessed Resource Adequacy Availability Incentive Mechanism (RAAIM) penalties.

For these reasons, CalCCA opposes option three. The CAISO should adopt option one in Track A and consider whether or not to adopt option two at a later date. Option two may be duplicative of RAAIM charges. However, it is unclear if RAAIM is effective at incenting supply to be available to meet its RA obligations. If the CAISO transitions away from RAAIM to another availability incentive, like unforced capacity, it may be prudent to revisit option two at a later date.

5. Provide your organization's comments on scope item #3 – criteria to set the ISO BAA's net

EDAM export transfer constraint:

The CAISO asks how to set the optional “confidence factor” that will be used to account for the deliverability of non-RSE eligible supply, like economic imports with untagged day-ahead schedules. Using historical data on the deliverability of non-RSE eligible supply appears to be the best data source for setting the confidence factor.

The CAISO also asks how the CAISO should set the conditions for using the “additional margin” to constrain the CAISO BAA’s net EDAM export transfers. CalCCA supports the list of conditions included in the CAISO presentation, including Flex Alerts, D+2 RUC infeasibilities, and the RA outlook (Slide 30), as each of these conditions can signal stressed system conditions.

In this initiative, the CAISO and stakeholders should also consider how the CAISO would set the additional margin percentage once triggered. In the example on Slide 29, it appears in HE 12, the CAISO could set the additional margin anywhere from 0 megawatts (MW) - 3,000 MW. Once triggered, would the CAISO set the additional margin at the maximum amount or would there be an additional decision point deciding where to set the additional margin once one of the conditions on Slide 30 has been met.

6. Provide your organization’s comments on scope item #4 – transfer resource settlement and transfer revenue distribution:

Transfer resource settlement payments should be allocated in a manner that is consistent with how the charges are allocated.

7. Provide your organization’s comments on scope item #5 – historical wheeling access charge recovery process:

Currently, wheel through and export energy from the CAISO BAA is subject to the WAC. Under EDAM, instead of receiving export schedules, the market will determine transfer energy schedules at transfer locations with other EDAM entities, and these transfer schedules will not be subject to WAC. The EDAM policy establishes a mechanism for recovering foregone WAC revenues. The question of how to establish foregone WAC revenues is a complicated one, and at this point, CalCCA has additional questions, rather than recommendations.

Does the CAISO anticipate that historical usage will reflect what usage would have been at that time under an EDAM?

As the transmission system changes, flows on the transmission system will also change. How will new transmission affect flows relative to historical flows? How will the CAISO determine whether the WAC charge would increase or decrease based upon these changes?

Would the CAISO use the last three years’ historical usage prior to EDAM implementation going forward or rolling three years’ historical usage?

It is unclear at this point how to accurately capture historical WAC revenues given the impacts EDAM will have on schedules and WAC’s dependency on the current state of the transmission system.

8. Provide any additional comments on the April 5, 2023 EDAM ISO BAA Participation Rules

stakeholder workshop discussion:

CalCCA has no additional comments at this time.

**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 E-MAIL
RULING ON COMMENT SCHEDULE FOR LOCAL CAPACITY REQUIREMENT
REPORT AND FLEXIBLE CAPACITY REQUIREMENT REPORT**

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April 19, 2023

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SUMMARY OF COMMENTS

- The California Independent System Operator Corporation and the California Public Utilities Commission are taking important steps to reduce reliance on carbon-emitting resources in local areas. The California Community Choice Association encourages the continued study of the ability to reduce reliance on fossil fuel resources in local areas as soon as possible to ensure an orderly and reliable transition from reliance on fossil fuels in local areas at least cost.

**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 E-MAIL RULING ON COMMENT SCHEDULE FOR LOCAL CAPACITY REQUIREMENT REPORT AND FLEXIBLE CAPACITY REQUIREMENT REPORT

California Community Choice Association¹ (CalCCA) submits these Comments in response to the *E-Mail Ruling on Comment Schedule For Local Capacity Requirement Report and Flexible Capacity Requirement Report*,² dated April 10, 2023, and comments on *California Independent System Operator Corporation Draft 2024 Local Capacity Technical Report*, dated April 6, 2023.³

I. INTRODUCTION

The CalCCA appreciates the opportunity to comment on the California Independent System Operator’s (CAISO) Draft 2024 Local Capacity Requirements (LCR) Report (Draft Report). The Draft Report highlights the importance of studying local capacity areas in a manner

¹ California Community Choice Association represents the interests of 24 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, Energy For Palmdale’s Independent Choice, Lancaster Choice Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy: <https://cal-cca.org/>.

² *E-Mail Ruling On Comment Schedule For Local Capacity Requirement Report and Flexible Capacity Requirement Report*, R.21-1-002 (Apr. 10, 2023) (Ruling): <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M506/K170/506170385.PDF>.

³ *California Independent System Operator Corporation Draft 2024 Local Capacity Technical Report*, R.21-10-002j (Apr. 6, 2023) (Draft Report): <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M505/K462/505462894.PDF>.

that ensures reliable operations under a zero-carbon grid as the state transitions away from its reliance on fossil fuel resources in local capacity areas. CalCCA encourages the continued study of the ability to reduce reliance on fossil fuel resources in local areas as soon as possible to ensure an orderly and reliable transition from reliance on fossil fuels in local areas at least cost.

II. THE CAISO AND THE COMMISSION ARE TAKING IMPORTANT STEPS TO REDUCE RELIANCE ON CARBON-EMITTING RESOURCES IN LOCAL AREAS

In the California Public Utilities Commission’s (Commission) Integrated Resource Planning (IRP) proceeding (R.20-05-003), CalCCA and other parties recommended that the Commission, in coordination with the CAISO, begin explicitly studying the ability to reliably serve load in local areas and disadvantaged communities with reduced reliance on fossil fuel resources. Specifically, CalCCA requested that the next sensitivity portfolios transmitted from the Commission to the CAISO for study in the Transmission Planning Process (TPP) should contemplate the retirement of fossil fuel resources in the local areas.⁴ In response to these requests and to the direction in Senate Bill 887,⁵ which requires the Commission to look at ways to reduce reliance on non-preferred resources in local areas, the Commission states in its D.23-02-040:

The importance of planning for additional natural gas plant retirements has been a priority for us for some time and Commission staff have begun work to develop this type of analysis. The analysis is complex, and we commit to beginning a process for stakeholder input on it in 2023. If it is ready, we will include it in consideration for a sensitivity analysis in the next TPP cycle.⁶

⁴ *California Community Choice Association’s Reply Comments on Administrative Law Judge’s Ruling Seeking Comments on Electricity Resource Portfolios For 2023-2024 Transmission Planning Process*, Rulemaking (R.) 20-05-003 (Nov. 10, 2022), at 3:
<https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M498/K526/498526150.PDF>.

⁵ Senate Bill No. 887 Consumer affairs:
https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=202320240SB887.

⁶ Decision (D.) 23-02-040, *Decision Ordering Supplemental Mid-Term Reliability Procurement (2026-2027) and Transmitting Electric Resource Portfolios to California Independent System Operator for 2023-2024 Transmission Planning Process*, R.20-05-003 (Feb. 23, 2023), at 78:
<https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M502/K956/502956567.PDF>.

The Draft Report highlights the importance of conducting this assessment as soon as possible. The ability to retire fossil fuel resources in local areas will depend on either (1) eliminating transmission constraints that limit the number of resources capable of serving load in the local area, or (2) bringing online enough effective carbon-free resources inside of the local area to replace the existing fossil fuel resources. The Draft Report shows that new transmission can significantly reduce local area requirements - requirements in the LA basin dropped by over 40 percent, from 7,529 megawatts (MW) in 2023 to 4,413 MW in 2024, due to new transmission.⁷ These results demonstrate that when cost-effective, new transmission can be extremely effective at reducing reliance on carbon-emitting resources inside the local area by increasing the ability to import clean resources outside the local area to load centers. Additionally, the CAISO indicates that it considered the ability of projects recommended in its 2022-2023 Draft Transmission Plan to reduce local capacity requirements and found that “there are 12 projects recommended for approval as reliability-driven and policy-driven that will increase the transmission capability into local areas.”⁸ Because local areas depend heavily on gas-fired resources, it will be critical for the CAISO and the Commission to identify when transmission can cost-effectively reduce LCRs to meet state policy goals. The CAISO and the Commission are on the right track and CalCCA encourages the continued study of the ability to reduce reliance on fossil fuel resources in local areas as soon as possible to ensure an orderly and reliable transition from reliance on fossil fuels in local areas at least cost.

⁷ Draft Report at 2 and 4: <http://www.caiso.com/InitiativeDocuments/Draft-2024-Local-Capacity-Technical-Report.pdf>.

⁸ Draft CAISO *2022-2023 Transmission Plan* (Apr. 3, 2023), at 102: <http://www.caiso.com/InitiativeDocuments/Draft-2022-2023-Transmission-Plan.pdf>.

III. CONCLUSION

For all the foregoing reasons, CalCCA respectfully requests consideration of the comments herein.

Respectfully submitted,



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

April 19, 2023

Docket No.: A.22-05-002 et al.

Exhibit No.: JCCA-01

Date: April 21, 2023

Witnesses: Various

Commissioner: John Reynolds

ALJs: Garrett Toy and Jason Jungreis

**PREPARED DIRECT TESTIMONY OF THE
JOINT COMMUNITY CHOICE AGGREGATORS**

**APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY (U39E) FOR
APPROVAL OF ITS DEMAND RESPONSE PROGRAMS, PILOTS AND
BUDGETS FOR PROGRAM YEARS 2023-2027**

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Attachments

- Attachment A:** Description of MCE DR Program
- Attachment B:** Description of SCP DR Program
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- Attachment D:** Description of PCE DR Program
- Attachment E:** Witness Qualifications

Table of Witnesses

<u>Title</u>	<u>Witness</u>
Prepared Direct Testimony of Joint Community Choice Aggregators	Alice Havenar-Daughton
Attachment A: Description of MCE DR Program	Alice Havenar-Daughton
Attachment B: Description of SCP DR Program	Rebecca Simonson
Attachment C: Description of EBCE DR Program	Feliz Ventura
Attachment D: Description of PCE DR Program	Peter Levitt
Attachment E: Witness CVs	Alice Havenar-Daughton Rebecca Simonson Feliz Ventura Peter Levitt

1 **I. INTRODUCTION AND RECOMMENDATIONS**

2 In this testimony, the Joint Community Choice Aggregators (Joint CCAs)¹ address Phase
3 II Scoping Issue 9: Should dual participation rules be modified or clarified?² The Joint CCAs
4 answer: Yes. The California Public Utilities Commission (CPUC or the Commission) established
5 dual participation rules over ten years ago.³ The purpose of those rules was to increase the
6 demand response (DR) resource available to the state and ensure that customer load reductions
7 were not double counted. While those objectives remain relevant today, three factors require that
8 the Commission revisit the dual participation rules.

9 First, the DR landscape in California has become increasingly complex. Both DR
10 program types and program providers have diversified, whereas the rules generally reflect
11 outdated, binary distinctions between program types (energy vs capacity, and day-ahead vs day-
12 of distinctions).⁴ Second, in recent years, load modifying DR programs⁵ have become
13 increasingly prominent. Community choice aggregators (CCAs), for instance, already offer

¹ The Joint CCAs consist of East Bay Community Energy (EBCE), Marin Clean Energy (MCE), Peninsula Clean Energy Authority (PCE), the City of San José – which operates and administers San José Clean Energy (SJCE) through the City’s Community Energy Department, and Sonoma Clean Power Authority (SCP). Each of the CCAs in the Joint CCAs is located in Northern California, and therefore focus their testimony and participation in this proceeding on issues relevant to Pacific Gas and Electric Company’s (PG&E) Application. On June 6, 2022, MCE timely filed a response to PG&E’s Application for Approval of its Demand Response Programs, Pilots and Budgets for Program Years 2023-2027, and is therefore a party to this proceeding pursuant to Commission Rule 1.4(a)(2). EBCE, PCE, SCP and the City of San José filed motions for party status in this proceeding pursuant to Commission Rule 1.4(a)(4) on April 20, 2023. At the time this testimony was filed, those motions for party status were pending.

² Application (A.) 22-05-002 et al., Assigned Commissioner’s Amended Scoping Memo and Ruling and Assigned Administrative Law Judge’s Ruling on Two Motions at 6 (Dec. 19, 2022).

³ D.09-08-027 at 154-158; OP 30.

⁴ See A.22-05-002 et al., PG&E Direct Testimony, Exhibit PGE-2 at 2-8 to 2-9.

⁵ The Commission distinguished load modifying and wholesale market-integrated DR programs in D.14-03-026. Load modifying DR reshapes or reduces the net load curve. Market-integrated DR is, by definition, integrated into the CAISO market. D.14-03-026 COL 5, OPs 2-3.

1 several load-modifying DR programs, and will offer new load-modifying DR programs in the
2 near future.⁶

3 Second, six of the eight sub-programs in the investor-owned utility (IOU)-administered
4 Emergency Load Reduction Program (ELRP)—which represents over 50% of PG&E’s 2023-
5 2027 DR portfolio budget⁷—are load modifying programs. The dual participation rules, and
6 associated processes, require updates to ensure that PG&E and CCAs regularly exchange load-
7 modifying DR program participation data and avoid double counting customer load reductions.

8 Third, extreme weather increasingly strains California’s grid. As the Governor’s 2021
9 and 2022 Emergency Proclamations⁸ make clear, DR can be a critical tool to relieve that strain.
10 In order for DR providers and customers to meet the needs of this “all-hands-on-deck” moment,
11 the dual participation rules must be updated and clarified to ensure that customers neither
12 “double dip” nor are unduly precluded from providing distinct grid services by participating in
13 more than one DR program.

14 The Joint CCAs therefore make the following recommendations to the Commission:

- 15 ● Adopt PG&E’s recommendation that the Commission convene a workshop in this
16 proceeding to address modifications and updates to the dual participation rules,
17 and;
- 18 ● Establish a process whereby PG&E and CCAs transparently exchange program
19 participation data on load modifying DR programs.
20

⁶ See A.22-05-002 et al., MCE Response to the Application of Pacific Gas and Electric Company for Approval of its Demand Response Programs, Pilots and Budgets for Program Years 2023-2027 at 4 (Jun. 6, 2022).

⁷ A.22-05-002 et al., Application of Pacific Gas and Electric Company for Approval of its Demand Response Programs, Pilots and Budgets for Program Years 2023-2027 (PG&E Application) at 20-21 (May 2, 2022).

⁸ Proclamation of a State of Emergency, Executive Department State of California (Jul. 30, 2021) available at: <https://www.gov.ca.gov/wp-content/uploads/2021/07/Energy-Emergency-Proc-7-30-21.pdf>, Proclamation of a State of Emergency, Executive Department State of California (Aug. 31, 2022), available at: <https://www.gov.ca.gov/wp-content/uploads/2022/08/8.31.22-Heat-Proclamation.pdf?emrc=78e3fc>.

1 **II. OVERVIEW OF CCA DEMAND RESPONSE PROGRAMS**

2 The dual participation rules—as well as the processes and systems in place to limit dual
3 participation—impact the Joint CCAs’ interests because CCAs have launched several DR
4 programs in recent years and will implement new programs in the near future. Attachments A-D
5 to this testimony describe the Joint CCAs’ respective DR programs in detail. Those programs
6 include event-based DR, daily load shifting, managed electric vehicle (EV) charging, energy
7 storage dispatch, and hybrid offerings. While the CCAs’ diverse DR offerings feature a variety
8 of participation models and structures, they are each focused on achieving a common objective:
9 enabling and incentivizing customers to deliver load reductions during critical times in order to
10 reduce strain on the grid. Importantly, each of those offerings implicate dual participation issues
11 because customers participating in (or desiring to participate in) CCA DR programs may also be
12 enrolled in the ELRP or other IOU load-modifying DR programs. Below, the Joint CCAs address
13 the dual participation rules and recommend the Commission create a streamlined process that
14 allows the CCAs and PG&E to prevent inappropriate dual participation in their respective load-
15 modifying DR programs going forward.

16 **III. SCOPING ISSUE 9: THE DUAL PARTICIPATION RULES SHOULD BE**
17 **MODIFIED.**

18 **A. The Commission should revisit the dual participation rules in light of the**
19 **growth of load-modifying DR programs.**

20 The Commission established dual participation rules over ten years ago.⁹ At a high level,
21 those rules aimed to *increase* the amount of cost-effective DR available while ensuring that the
22 same load reduction is neither counted nor compensated twice.¹⁰ The rules allow customers to
23 participate concurrently in more than one DR program provided:

⁹ D.09-08-027 at 154-158; OP 30.
¹⁰ D.09-08-027 at 154-158; D.18-11-029 at 7.

- 1 1. Customers are not paid twice for the same load reduction;
- 2 2. One program is day-ahead and the other is day-of;
- 3 3. Only one of the two programs may pay a capacity payment;
- 4 4. During simultaneous events and if both programs offer energy payments,
- 5 one of the energy payments is withheld.¹¹
- 6

7 Since the Commission first adopted the dual participation rules above, both the DR
8 program landscape, as well as the needs of California’s electricity system, have evolved. In
9 recent years in particular, load-modifying programs—including all of the DR programs offered
10 by CCAs, as well as several of the sub-programs under the ELRP—have become increasingly
11 prominent. Those programs offer customers a variety of options to benefit the grid by reshaping
12 the net load curve, and the opportunity to provide distinct services.

13 The dual participation rules, however, have not kept up. As PG&E correctly observes,
14 while dual participation rules serve important purposes—chiefly: avoiding double counting and
15 double compensating the same instance of load reduction and ensuring accurate load impact
16 measurement and attribution—existing dual participation rules “are neither complete nor
17 contemplate increasing complexity.”¹² The Joint CCAs agree with PG&E that the rules “are ripe
18 for discussion through a workshop early in this application proceeding.”¹³ The Joint CCAs
19 further agree that a workshop “may also be helpful in navigating the complexity of dual
20 participation with Community Choice Aggregator (CCA) programs”.¹⁴ The Joint CCAs therefore
21 submit that the Commission should revisit the dual participation rules, and recommend that the
22 Commission convene a workshop in this proceeding to address modifications and updates to the
23 dual participation rules, consistent with PG&E’s recommendation in its direct testimony.

11 D.18-11-029 at 15 (summarizing rules adopted in D.09-08-027).

12 A.22-05-002 et al., PG&E Direct Testimony, Exhibit PGE-02 at 2-9:1.

13 *Id.* at 2-9:10-11.

14 *Id.* at 2-9:fn14.

1 **B. The Commission should establish a streamlined process that allows PG&E and**
2 **CCAs to exchange DR program participation data and verify customer**
3 **eligibility for load-modifying DR programs.**

4 In its testimony, PG&E offers a series of principles to guide modifications to the dual
5 participation rules.¹⁵ The Joint CCAs largely support PG&E’s proposed principles. Like PG&E,
6 the CCAs—who already offer several load management programs—require “transparency,
7 systems, and processes”¹⁶ to track participation in conflicting programs. Those processes already
8 exist in the context of California Independent System Operator (CAISO) market-integrated DR
9 programs. The IOUs and third-party Demand Response Providers (DRPs) coordinate a process
10 that tracks participation in potentially conflicting programs via the CAISO’s Demand Response
11 Registration System (DRRS).¹⁷

12 A similar process does not, however, exist for load-modifying DR programs. This is a
13 major gap. Again, as the Joint CCAs explained above, load-modifying DR programs represent a
14 growing share of DR program offerings: all of the DR programs the CCAs currently offer are
15 load-modifying programs, and six out of the eight sub-programs under the ELRP—which
16 represents over 50% of PG&E’s 2024-2027 DR portfolio budget¹⁸ and has already auto-enrolled
17 over 1.5 million residential customers—are load-modifying DR programs. The Joint CCAs
18 therefore strongly recommend that the Commission direct the development of a streamlined
19 process in this proceeding to ensure CCAs and PG&E regularly exchange program participation
20 data and effectively prevent double counting customer load reductions.

15 *Id.* at 2-10.

16 *Id.*

17 See California ISO, Demand Response Registration User Guide, Version 4.9 (Oct. 28, 2020), available at:
<http://www.caiso.com/Documents/DemandResponseRegistrationUserGuide-clean.pdf>.

18 See A.22-05-002 et al., PG&E Application at 20-21.

1 In its simplest form, that process could involve a monthly or quarterly exchange of load
2 modifying DR program enrollment data in spreadsheet format between PG&E and CCAs via a
3 secure file sharing site (sftp site). In that scenario, the spreadsheet would include basic customer
4 identification data (e.g. SAID, customer name, and site address), as well as nominated or
5 forecasted load reduction expected to be provided by the resource during DR events. A slightly
6 more sophisticated solution for data exchange would involve a single database that registers
7 resources participating in PG&E and CCA load-modifying DR programs (similar to the CAISO’s
8 DRRS for market-integrated programs). This database, which would contain all of the same
9 customer data points listed above, could be administered by the CPUC or by the California
10 Energy Commission (CEC).

11 At minimum, the data exchange process would allow PG&E and the CCAs to prevent
12 dual-enrollment in both a CCA and a PG&E load-modifying DR program. Specifically, the Joint
13 CCAs recommend that PG&E unenroll customers already participating in a CCA load modifying
14 DR program from the ELRP or other PG&E load modifying DR program within **5 days** of
15 receiving program participation data from the CCA. The Joint CCAs note that a process that
16 allows seamless unenrollment from the ELRP is consistent with the Commission’s prior
17 directives. In D.21-12-015, the Commission stated: “customers participating in the Residential
18 ELRP may at any time enroll in a supply-side DR program offered by the IOU, registered third-
19 party DRP or CCA and shall be promptly unenrolled by the IOU from ELRP without the need
20 for any action on the part of the customer.”¹⁹ It is reasonable for IOUs to act with similar speed
21 when its ELRP customers have chosen to enroll in one of the many *load-modifying* DR programs
22 offered by CCAs, and the Commission should clarify that requirement here.

¹⁹ D.21-12-015 at 58.

1 While unilateral data transfer (i.e., CCAs send participation data to PG&E) would allow
2 PG&E to timely unenroll dual-participating customers, the Joint CCAs recommend a bilateral
3 data exchange process (for example: MCE would send PG&E its Peak FLEX program
4 enrollment data and PG&E would send MCE its ELRP and other load modifying DR program
5 enrollment data). A bilateral exchange would improve each LSE’s insight into the forecasted
6 load reductions for their respective customer bases, allowing each LSE to make more accurate
7 bidding and scheduling decisions on a daily basis. Without a bilateral exchange, CCAs have
8 limited visibility into their customers’ anticipated load reductions (and when those reductions
9 might occur), which constrains their ability to plan and dispatch their own resources effectively.

10 Importantly, CCAs have grown to serve approximately one third of load in CA and are
11 the default electricity provider in their areas, tending to serve 85% or more of the customers in
12 their member jurisdictions. More accurate forecasting of demand response participation by
13 customers helps LSEs optimize how much energy to buy and reduces costs for ratepayers. As a
14 result, CCAs have a material and growing interest in the load forecasting impacts of programs
15 serving their customers. The Commission should order the bilateral exchange of information for
16 load forecasting purposes so CCAs have data to improve forecasting and limit over procurement
17 for customers engaging in DR programs.

18 The Joint CCAs observe that a program participation data exchange process is not a novel
19 idea—MCE has successfully addressed dual enrollment and double dipping prevention in other
20 program areas. Yet, while DR programs implicate many of the same “double-dipping” concerns
21 as EE programs, PG&E has not been receptive to implementing a similar process in the DR
22 context. Almost 103,000 residential customers in MCE’s service area were auto-enrolled in the
23 Residential ELRP (i.e., PG&E’s Power Saver Rewards Program). In order to prevent the dual

1 enrollment of its customers in the Residential ELRP and MCE’s Peak FLEXmarket, MCE
2 reached out to PG&E to discuss the implementation of a program participation data exchange
3 process. Despite MCE’s repeated outreach since September 26, 2022, it has found PG&E to be
4 non-responsive. As a result, PG&E and MCE continue to lack an effective means of preventing
5 dual participation in load-modifying DR programs.

6 To streamline the CCAs’ and IOUs’ coordination on limiting dual participation and
7 mitigate the issues described above going forward, the Commission must:

- 8 ● Direct the parties to develop, as a part of a broader workshop addressing the dual
9 participation rules, a streamlined process whereby PG&E and the CCAs
10 exchange program participation information in load modifying DR programs,
11 and;
- 12 ● Approve a program participation data exchange process in its final Order in this
13 proceeding for use in performing dual participation verifications and in load
14 forecasting.

15
16 **IV. CONCLUSION**

17 This concludes the Joint CCAs’ direct testimony.

Attachment A

Description of MCE DR Program

MCE currently runs three load management programs and is developing a virtual power plant (VPP) project that are all geared at reducing peak load both during emergency events and on a daily basis. First, the *Peak FLEXmarket* program is a demand DR program that MCE launched on June 1, 2021, which is uniquely capable of achieving peak load reduction at scale. The program assigns an hourly value to measured, behind-the-meter (BTM) load reduction impacts based on the Commission's Avoided Cost Calculator (ACC). The *Peak FLEXmarket* offers compensation for both daily load shifting and event-driven DR, or DR alone. One of the primary attributes of a price-signal driven program is that it enables the *Peak FLEXmarket* to remain technology agnostic – it is simply a program framework with the tools to measure and value hourly reductions in energy use. In other words, customers and/or aggregators can participate under the *Peak FLEXmarket* with a behavioral DR offering, a device-enabled strategy (e.g., batteries, smart thermostats), or any other solution that generates verifiable results at the meter. By offering a payment for energy reductions that values a range of resources equally, the *Peak FLEXmarket* ensures that incentives flow to projects with verifiable impacts and allows for different BTM solutions to work together in a coordinated way.

Second, MCE developed an *Energy Storage Program* and an Electric Vehicle (EV) charging program—*MCE Sync*—that are each designed to align customer charging and discharging behaviors of the respective DERs with grid needs and to reduce demand during times of grid stress. MCE's *Energy Storage Program* offers compensation to participating customers (both residential and non-residential) in exchange for agreeing to dispatch their energy storage system (ESS) daily during the 4-9pm peak hours. In exchange, customers are

provided with different types of up-front and performance-based incentives to lower the cost of the ESS. Under the *MCE Sync* program, MCE and its implementation partner ev.energy enrolled around 1,500 customers who charge their EVs at home into the ev.energy platform, which delivers direct load control over their EV charging using vehicle telematics and networked electric vehicle supply equipment (EVSE). The goal of the program is to deliver regular load shifting away from the 4pm - 9pm peak window, while aligning as much EV charging as possible with high-solar daytime hours. Program participants have also successfully participated in MCE's *Peak FlexMarket* in 2022 to provide load reductions during DR events.

Finally, MCE is also developing a VPP in the city of Richmond under the *Advanced Energy Community (AEC) Project*. Under the project, MCE and its partners will rehabilitate up to 100 abandoned homes, as well as larger commercial and industrial sites, with low- to no-cost energy efficiency and electrification equipment to establish a VPP. The VPP will include smart, clean energy technologies including energy storage, smart thermostats, rooftop solar, heat pump space and water heating, and EV charging. These appliances will be networked and aggregated to receive market signals from MCE and partners based on grid needs. This will reduce customer bills, contribute to grid reliability, and further reduce electricity sector emissions.

Attachment B

Description of SCP DR Program

SCP has a portfolio of load management and demand response programs that focus on permanently shifting load as well as curtailing load during emergency or high-demand events.

GridSavvy Rewards is a demand management program that provides multiple options for customers including *GridSavvy Rewards-Alerts* (behavioral) and *GridSavvy Rewards-Smart Devices* (auto-DR for devices such as EV chargers, smart thermostats, and (coming soon) battery storage).

SCP launched the *GridSavvy Rewards-Alerts* program in May 2022, in response to summer reliability concerns, where no smart devices are needed. Customers receive alert notifications through phone or email to save energy during hours of high demand on the grid and conserve energy through any means that works for them. *GridSavvy Rewards-Alerts* pays customers \$2 for every kilowatt-hour (kWh) saved from their baseline during an Energy Saving Event. Customers may also choose to donate their rewards to a selection of local Community Partners. SCP directly targeted low-income customers and customers that use the most electricity during summer peak hours. SCP reached customers that have historically been left out of programs; most notably Spanish speakers and customers that do not have services (e.g., internet, email, cell phones). Since the program started through December 31, 2022:

- 19 Energy Saving Events were called between May and September 2022, including 11 during the CAISO Flex Alerts in early September alone;
- 2,010 customers enrolled;
- 72% are enrolled in CARE/FERA;
- 45 customers chose to receive communications in Spanish;

- Participating customers reduced total peak demand, on average, by 500 kilowatts (kW) on September 6th (peak 2022 day); and
- Participating customers saved a cumulative total of approximately 34,000 kWh during peak hours.

GridSavvy Rewards-Smart Devices automates shifting energy use from peak times. SCP offers discounts and incentives to purchase and connect smart devices, such as EV chargers, smart thermostats, and water heaters. These smart devices can receive a remote signal from SCP, which automatically adjusts usage while making energy-saving choices easy. As of December 31, 2022:

- 880 EV chargers are currently enrolled in GridSavvy Rewards; and
- 350 smart thermostats are enrolled in GridSavvy Rewards or have indicated they will enroll.

As part of *GridSavvy Rewards-Smart Devices*, SCP is developing battery storage optimization programs for residential customers that have installed battery storage systems. SCP is currently in contract negotiation for implementing this program and expects to launch in August 2023. Data has shown that many residential customers install battery storage systems for backup purposes that only operate when there is a power outage. SCP will incentivize customers to allow SCP to manage a portion of their batteries daily to provide grid benefits, reduce greenhouse gas emissions, and reduce procurement costs. SCP will signal the batteries to charge during the day when renewable supply is high and power costs are low and to discharge the batteries in the ramping hours when solar energy is limited, but demand and prices are high. SCP will coordinate with weather forecasts and Public Safety Power Shutoffs to allow the customer to still have full charge in the event of a predicted power outage.

SCP is also developing programs for workplace charging and telematics-based EV charging management that are not launched yet, but are aimed at shifting EV charging to hours where renewable energy supply is available. Recent studies have shown that shifting drivers from nighttime home charging to daytime charging when renewable energy, such as solar, is abundant on the grid has many positive grid impacts. Daytime charging reduces impacts from evening ramping (when solar energy decreases while residential energy use increases), reduces use of fossil fuel electricity generation, brings more value to both customer-sited and utility renewable generation, reduces battery storage build-out requirements, and reduces greenhouse gas emissions. Daytime charging also allows the grid to better support higher levels of EV adoption.

Attachment C

Description of EBCE DR Programs

In the *Resilient Home* program, EBCE partners with solar company Sunrun, which assists customers with installing behind-the-meter solar and battery systems and provides an option for financing the systems. The program provides incentives to customers that allow EBCE to dispatch the batteries every weekday during the evening peak hours. With over 1,000 residential solar and storage systems under management, EBCE delivers peak load management on a daily basis, including on CAISO peak days. Each residential battery delivers approximately 2 kilowatts (kW) over a 4-hour period (8 kWh) every weekday. Batteries are coordinated to charge at controlled rates during times of high solar generation and discharge at a consistent rate across times of peak grid load. EBCE will continue to build on its expertise in delivering consistent load shifting over the course of a 10-year contract with Sunrun for this program.

Additionally, EBCE is piloting an EV managed charging program – *EBCE Smart Charge* – to better understand the potential for residential managed charging. Through this pilot, EBCE and its implementation partner Kaluza have enrolled over 100 customers that receive up-front and monthly incentives for participation. These customers interface with an app that uses the Kaluza Platform, which delivers direct load control, to shift customer vehicle charging load from on-peak to off-peak periods.

Finally, EBCE is in the early stages of developing a grid services program, which will prioritize the cost-effective management of peak load for high usage customers while further encouraging electrification and decarbonization.

Attachment D

Description of PCE DR Programs

In the *Solar and Battery Backup* program, PCE partners with solar company Sunrun, which assists customers with installing behind-the-meter solar and battery systems and provides an option for financing the systems. The program provides incentives to customers that allow PCE to dispatch the batteries every weekday during the evening peak hours. With over 1,000 residential solar and storage systems under management, PCE delivers real, ongoing peak load management on a daily basis, including on CAISO peak days. Each residential battery delivers approximately 2 kilowatts (kW) over a 4-hour period (8 kWh) every weekday. Batteries are coordinated to charge at controlled rates during times of high solar generation and discharge at a consistent rate across times of peak grid load.

Under its *Managed Charging* program, PCE and its implementation partner ev.energy are currently enrolling customers who will integrate their EVs at home into the ev.energy platform, which delivers direct load control over their EV charging using vehicle telematics and networked electric vehicle supply equipment (EVSE). The initial aim of this program is to deliver regular load shifting away from the 4pm - 9pm peak window, while aligning as much EV charging as possible with high-solar daytime hours.

Attachment E

Witness Qualifications

Alice Havenar-Daughton

Director of Customer Programs, MCE
1125 Tamalpais Ave, San Rafael, 94901

RELEVANT SKILLS AND EXPERIENCE

- Strong background in energy efficiency, with experience in program design, implementation, and evaluation.
- Oversees implementation of energy programs with over \$10 million annually in the Marin Clean Energy service territory.
- Oversaw program launch of MCE's first low-income multifamily energy efficiency program, the Low-Income Family and Tenants (LIFT) Pilot Program.

EDUCATION

American University, Washington DC, 2010
M.A. Natural Resources and Sustainable Development
McGill University, Montreal, Canada, 2005
B.SC. Architecture

WORK EXPERIENCE

MCE San Rafael, CA, May 2018 – Present

Director of Customer Programs

- Oversees MCE's portfolio of customer programs, including energy efficiency, transportation electrification, low-income solar.
- Represents MCE externally in stakeholder forums such as California Energy Efficiency Coordinating Committee (CAEECC) and CalTF, and through speaking engagements.
- Lead the development of a new program data tracking tool for program performance and streamline reporting.

MCE San Rafael, CA, June 2017 – April 2018

Manager of Policy and Planning, Customer Programs

- Oversees planning for Demand Side Resource Pilot Programs, including, electric vehicles, fuel switching and low-income solar.
- Works collaboratively with MCE's Regulatory Team to develop the strategy for MCE's engagement with the California Public Utilities Commission (CPUC) in the Business Plan Application process, including developing content for filings, drafting talking points, engaging with partners and 1 serving as MCE's representative to the CAEECC.
- Manages MCE's EM&V budget for Energy Efficiency Programs and LIFT.
- Oversees all Energy Efficiency and LIFT program reporting to the CPUC.
- Manages MCE's SF Seasonal Savings Program, the California Energy Commission (CEC) BEO Grant and grant compliance for the electric vehicle charges owned by MCE.

MCE San Rafael, CA, October 2015 – June 2017

Energy Efficiency Program Manager

- Managed MCE's Single-Family Energy Efficiency Program.
- Managed all energy efficiency programs reporting to the California Public Utilities Commission.
- Supported MCE's Business Plan Application through sector chapter development, managing cost effectiveness work done by consultants and leading the internal program logic model and metrics development.
- Represented MCE through engagement and comments on several CPUC-funded EM&V studies of MCE's programs.

MCE San Rafael, CA, July 2014 – October 2015

Energy Efficiency Specialist

- Developed tracking systems for MCE's Energy Efficiency program expenditures and savings.
- Represented MCE at the Reporting Program Coordination Group at the CPUC.
- Tracked data and prepared monthly, quarterly and annual reports for the CPUC. Provided data necessary for other compliance requirements.

Opinion Dynamics Corporation Oakland, CA, November 2010 – July 2015

Senior Analyst

- Served as a lead analyst on process and impact evaluations of energy efficiency and demand response programs in California and across the county.

Alliance for Climate Protection Washington, DC, May 2010 – September 2010

Solutions/Policy Team Fellowship

- Analyzed national climate and energy legislation to support renewable energy advocacy effort.

**American Council for an Energy Efficient Economy (ACEEE) Washington, DC,
January 2010 – April 2010**

Buildings Team Intern

- Conducted research on barriers to energy efficiency in building codes.

Energetica Cochabamba, Bolivia, August 2008 – May 2009

Research Assistant

- Conducted a study on the potential for solar water heaters in urban areas of Bolivia which supported the initiation of a new solar water heater project, Proyecto ElSol.
- Assisted in rural educational workshops for subsidized solar panel recipients.

Rebecca Simonson, PE

707-364-3813 | rebeccasimonson@msn.com | Santa Rosa, CA

SUMMARY

Engineer and strategist with 19 years' experience in a variety of fields including implementing new organizational departments, building high functioning teams, power procurement, energy contracts negotiation and management, power services and planning, building services consulting, project development and management, data management and analytics, energy and water use analysis and benchmarking, master-planning sustainable developments, measurement and verification of water and energy efficiency and greenhouse gas emissions.

EXPERIENCE

- 2015-present **SONOMA CLEAN POWER, Santa Rosa, CA**
Director of Planning and Analytics
- Implemented new Planning and Analytics department and direct all functions relating to long-term power supply resource planning and responsible for developing customer rates and forecasting energy sales, demand, electricity revenues, and power costs.
 - Oversee and conducts analytical support for all Sonoma Clean Power departments.
- Power Services Manager**
- Managed all functions related to energy procurement, load forecasting, risk management, market monitoring, regulatory compliance, and California electricity grid operator (CAISO) settlements.
- 2011-2015 **SONOMA COUNTY WATER AGENCY, Energy Resources Group, Santa Rosa, CA**
Water Agency Engineer
- Developed and implemented projects to reduce the Agency's energy demands and to cost effectively generate local renewable power including small wind power, solar PV, biomass, landfill gas to energy, hydropower, recycled water heat pumps and electric vehicle charging stations.
 - Managed the Agency's Greenhouse Gas Inventory reporting to The Climate Registry.
 - Designed a solids dewatering system at the Sonoma Valley Wastewater Treatment Plant
- 2005-2010 **WSP, Sydney, Australia**
Director of Built Ecology
- Directed an engineering department specializing in sustainable building practices and designing and managing world class sustainable buildings, precincts and cities.
 - Managed a team and became the youngest member on the Board of Management.
 - Responsible for financial performance, job performance, and growth of the Sustainability team.
 - Project managed both small and large projects for commercial buildings, infrastructure, and communities.
 - Performed technical studies and reports including building energy simulation, daylight modeling, and computational fluid dynamic modeling.
- 2002-2005 **EMCOR ENERGY & TECHNOLOGIES, San Francisco CA**
Energy Engineer
- Audited commercial, industrial, governmental, and residential buildings across the United States to establish, analyze, and recommend potential energy efficiency measures.
- Summer 2001 **SUSTAINABLE BUILDING INDUSTRIES COUNCIL (SBIC), Washington D.C.**
Sustainable Building Intern
- Promoted, educated, and researched energy-efficient and sustainable design and planning in buildings.

EDUCATION

- 2013-2015 **EXECUTIVE MBA**, Sonoma State University, Rohnert Park CA
- 2005-2007 **MASTER OF SUSTAINABLE DEVELOPMENT**, University of New South Wales, Sydney Australia
- 1998-2002 **B.S. MECHANICAL ENGINEERING**, University of California Santa Barbara (UCSB)
Department Honors & Distinction in the Major

ACHIEVEMENTS AND SKILLS

- Licensed as a Professional Mechanical Engineer in the state of California
- LEED BD+C Accredited Professional
- Leadership Institute for Ecology and the Economy
- Green Star (Australia) Accredited Professional
- Competent in modelling software Radiance, TAS8.5, EnergyPro, IES, eQuest, PHOENICS, StarCCM+, Ecotect
- Competent in sql queries and PowerBI
- Completed four marathons, multiple half marathons, and one century cycle
- Passion Speaker for the American Heart Association North Bay chapter

SUMMARY

Feliz M. Ventura is a proven strategist making the case for transformational climate-related investments using her experience across economics, social science, and technological development, while optimizing investments using social and ecological lenses. Feliz has designed new business models, developed cross-sector partnerships, and advised entities from cities to corporations on addressing climate change in the context of rapidly-changing technological, social and climatic conditions.

EXPERIENCE

RESILIENCE PROGRAM MANAGER, EBCE – 2022-PRESENT

Designing, structuring and implementing energy resilience investments in a region representing over \$100B in GDP and nearly 2M residents. Developing and engaging partners to deploy energy resilience technology in the public and private realms to scale up climate action and resilience. Leading EBCE's Critical Municipal Facility and Resilient Home programs, Grid Services program development and Disadvantaged Community Solar selection process.

CLIMATE CHANGE & SUSTAINABILITY LEAD FOR INFRASTRUCTURE, HATCH – 2020-2022

U.S. lead on carbon-reducing strategies and projects in the context of climate, technological and economic change. Advise and build cross-functional and multi-firm teams to deliver on objectives that include interlinked engineering, technological and economic considerations. Represent sustainability and resilience interests in public and internal settings, and develop strategic partnerships that advance these interests.

DIRECTOR OF SUSTAINABLE ECONOMICS, AMERICAS, AECOM – 2011-2019

Developed, structured and implemented projects across the Americas that guided governments and corporations through economic, strategic and implementation planning for long-lived investments in the context of changing climactic and technological conditions, including net zero targets. Partnered with key thought leadership organizations in sustainability, resilience, natural resources and climate change. Led San Francisco DEI Committee and member of Corporate DEI Committee.

PARTNER, INSIGHT ACCESS – 2010-2011

Analyzed markets and advanced manufacturing partnerships in the clean tech sector.

SENIOR CONSULTANT, COLUMBIA ECONOMICS – 2009-2010

Quantified financial and economic impacts of greenhouse gas cap and trade legislation.

CLEAN TECHNOLOGY PROGRAM MANAGER, STATE OF WASHINGTON – 2008-2009

Created and implemented statewide clean tech economic development program combining market development consulting with intergovernmental engagement resulting in export, financing and joint research/development agreements for companies in a range of stages. Economic analysis and policy contributor to Washington's Green Collar Jobs Plan and agency representative to the Western Climate Initiative's forest carbon rule-making working group.

NEW VENTURES ASSISTANT, WORLD RESOURCES INSTITUTE, DISTRICT OF COLUMBIA – 2004-2005

Developed standardized environmental, social and governance (ESG) impact standards for global application, measured impact from portfolio companies, and used data to promote investment in portfolio companies. Managed Brazilian office operations.

ENGAGEMENTS & PUBLICATIONS

2023 Solar Energy Innovation Symposium, Guest Attendee, U.S. Department of Energy, 2023.

Equitable Climate Resilience for U.S. Local Governments, Advisory Panel Member and Reviewer, Institute for Building Technology and Safety, 2022.

Global Reporting Initiative Disclosure and UN Sustainable Development Goals Report, Contributor. Hatch 2021.

Global Adaptation Month. Steering Committee Member, 2021.

Achieving Net Zero. Speaker, Future of London Conference, 2020.

Climate Proofing Your Hydro Asset. Ontario Waterpower Association Conference, 2020.

Public Infrastructure for an Equitable Future. Contributor. Onside Partners, 2020.

Funding and Financing for Hazard Mitigation in a Changing Climate. 2020 Orleans Parish Hazard Mitigation Planning Committee, 2019.

What's New in Adaptation Finance. Speaker, National Adaptation Forum, 2019.

Berkeley Energy Assurance Transformation (BEAT) Final Project Report: Advancing Clean Energy Microgrid Communities in an Urban Context. California Energy Commission. Publication Number: CEC-500-2019-014. 2019.

Paying for Climate Adaptation in California: A Primer for Practitioners. Resources Legacy Fund, 2018.

EDUCATION

UNIVERSITY OF CALIFORNIA AT SAN DIEGO, LA JOLLA, CA – MASTER OF SCIENCE, PUBLIC POLICY (2007)

Fully-supported Merit Scholar, Schoepflin Fellow for Sustainable Development, Faculty Research Fellow: USAID/TIES Center for US-Mexico Studies research and field work in Oaxaca, Mexico.

POMONA COLLEGE, CLAREMONT, CA – BACHELOR OF ARTS, INTERNATIONAL RELATIONS (2003)

Dean's List 2000-2003, Claremont Colleges Chicano-Latino Student Association Dean's List 2000-2003, International Study at Instituto de Ciencias Politicas at La Universidad Catolica de Chile and La Universidad de Chile, Athlete and leader on nationally-ranked women's rugby team.

ADDITIONAL LANGUAGES

Spanish

Portuguese

PETER LEVITT

San Francisco, CA ☎ 267-992-2513 ✉ levitt.peter@gmail.com

<https://www.linkedin.com/in/peter-levitt-53b70031/>

BUSINESS DEVELOPMENT & STRATEGY

Energy leader driven by having a direct impact on fighting climate change. Extremely passionate about renewables, energy storage, and decarbonization. American energy market expert focused on DERs and load shaping. Calculated strategist, negotiator, and business developer. Wide experience in starting new teams and efforts, and in managing commercial and legal risks during negotiations of partnership agreements, PPAs, and acquisition agreements.

CORE COMPETENCIES

- Partnership Cultivation
- Business Development
- Consultative Selling
- Project Execution
- Process Development
- Strategic Planning
- Energy and Capacity Markets
- Energy Finance
- Energy M&A
- American Utilities
- Virtual Power Plants
- Integrated DERs
- Load Shaping
- Fuel Switching
- Backup Power

PROFESSIONAL EXPERIENCE

Peninsula Clean Energy, Redwood City, CA June 2019 – Present

Manager / Associate Manager, Distributed Energy Programs and Strategy

- Designed and launched six DER programs, managing partnership development, program design, financial projections, internal and public approvals, contracting, and execution; 4MW of solar + 3MW/6.5MWh storage deployments to-date
- Created a new capacity product for distributed battery storage in partnership with Sunrun
- Published strategy documents on Energy Resiliency and Distributed Energy Programs that are projected to drive 25 – 55MW of new local solar + storage deployments, supporting PCE's goal of 100% around-the-clock renewable energy
- Serving as PCE's internal Subject Matter Expert on solar, storage, load shaping, VPPs, DR, and energy resiliency

SolarCity Corporation / Tesla Energy, Fremont, CA December 2014 – September 2018

Project Development Manager / Commercial Energy Consultant

- Created Tesla's first buy-side and sell-side M&A processes to transact projects under development, resulting in a development pipeline of over \$600M of commercial, industrial, and small utility projects
- Led negotiation of commercial and legal terms of project sale agreements, resulting in \$200M across 32 project sales
- Negotiated Right of First Offer agreements to secure financing outlets with NextEra and Cypress Creek Renewables
- Developed a pipeline of 145MW of non-residential solar+storage projects, leading to \$18M in booked deal value

Seed Consulting Group, San Francisco, CA August 2017 – Present

Executive Leadership Team – Head of Partnerships

- Executive leader of a nonprofit with over 600 volunteers, 120 consulting projects, and over \$5M in value delivered
- Leading a team of 20+ volunteers responsible for originating and scoping over 90 pro bono and low bono projects
- Developed the org's first low bono partnership structure with a Fortune 50 company

EDUCATION & LICENSES

B.S., Management, Entrepreneurial Focus - The Pennsylvania State University University Park, PA

B.A., Spanish, Business Focus - The Pennsylvania State University University Park, PA

Minor, International Studies - The Pennsylvania State University University Park, PA

Certified Scrum Master San Francisco, CA

PROFESSIONAL ORGANIZATIONS

NatureBridge Yosemite – Board Member 2019 – Present

Philadelphia City Repair Project – Board Member, Treasurer 2021 – Present

Toastmasters at Tesla - President and Co-founder 2015 – 2018

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

Application of Pacific Gas and Electric
Company (U39E) for Approval of its
Demand Response Programs, Pilots and
Budgets for Program Years 2023-2027

Application 22-05-002

And Related Matters.

Application 22-05-003

Application 22-05-004

**JOINT COMMUNITY CHOICE AGGREGATORS' RESPONSES TO QUESTIONS AND
ENERGY DIVISION STAFF PROPOSALS RELATED TO PHASE II ISSUES**

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*On behalf of Joint Community Choice
Aggregators*

April 21, 2023

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SUMMARY OF RECOMMENDATIONS

- The Commission should encourage self-enrollment and cease auto-enrollment in the residential Emergency Load Reduction Program (ELRP sub-group A.6);
- To the extent the Commission permits any level of auto-enrollment in the residential ELRP going forward, it should cease the auto-enrollment of Equity customers (i.e., customers enrolled in the CARE or the FERA programs), and instead focus auto-enrollment on high usage customers and sectors (such as residential customers with devices with high usage patterns like pool pumps, or sectors that have modifiable load like agricultural pumping);
- The Commission should prohibit charging by participating batteries in ELRP sub-group A.4 during ELRP event hours. Moreover, in order to better evaluate this issue, the Commission should direct the IOUs and the participating aggregator to explain when batteries were charged and discharged during each event in 2022, and provide a narrative explanation of why batteries charged during event hours;
- For non-residential customers participating in ELRP sub-groups A.1 and A.2, the Commission should establish a participation floor (expressed as a percentage of nominated capacity) tied to compensation, and compensate only those customers whose participation levels surpassed that floor;
- The Commission should direct the IOUs to clearly and simply outline the performance of the ELRP sub-groups both in terms of performance at the device- and at the meter-level so that parties can get a better sense of the true impacts of the ELRP. Following an opportunity for comment on those results, the Commission should issue a ruling addressing the appropriate measurement and compensation method for each ELRP sub-group;
- To the extent the Commission decides to extend the ELRP into 2026 and 2027, the ELRP should no longer be designated a pilot;
- The Commission should require IOUs provide the service list a redline describing proposed revisions to Rule 24/32 and allow parties an opportunity to comment. Further, to comprehensively address changes that may be necessary to the provisions of Rule 24/32 (including changes to define the role of the LSE), the Joint CCAs support a workshop dedicated to this issue;
- The Commission should adopt Energy Division Staff Proposal B, and;
- The Commission should adopt Energy Division Staff Proposal D, with the following modifications to ED’s proposed definition of a “qualified” DR program:
 - Supply-side market-integrated DR programs counted for Resource Adequacy, irrespective of whether the program administrator is an IOU, a CCA or a third-party DRP.
 - Load modifying DR programs integrated with CEC’s peak demand forecasting process (such as Critical Peak Pricing rates offered by the IOUs, and potentially marginal-cost-based dynamic pricing rates should the Commission adopt such rates in the future and

establish a process to integrate those rates with CEC’s forecasting process), irrespective of whether the program administrator is an IOU, a CCA or a third-party DRP.

- Any DR pilot authorized and designated by the Commission as a “qualified” DR program eligible to meet the DR enrollment requirement, irrespective of whether the program administrator is an IOU, a CCA or a third-party DRP.

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

Application of Pacific Gas and Electric Company (U39E) for Approval of its Demand Response Programs, Pilots and Budgets for Program Years 2023-2027

Application 22-05-002

And Related Matters.

Application 22-05-003

Application 22-05-004

JOINT COMMUNITY CHOICE AGGREGATORS' RESPONSES TO QUESTIONS AND ENERGY DIVISION STAFF PROPOSALS RELATED TO PHASE II ISSUES

Pursuant to the revised procedural schedule established in the January 27, 2023 *Assigned Commissioner's Ruling Directing Response to Questions and Energy Division Staff Proposals Related to Application 22-05-002 Phase II Issues and Directing Southern California Edison Company to Submit a Capacity Bidding Program Elect Proposal for Program Years 2024-2027* (January ACR), the Joint Community Choice Aggregators¹ (Joint CCAs) hereby submit the Responses below.

¹ The Joint CCAs consist of East Bay Community Energy (EBCE), Marin Clean Energy (MCE), Peninsula Clean Energy Authority (PCE), the City of San José – which operates and administers San José Clean Energy (SJCE) through the City's Community Energy Department, and Sonoma Clean Power Authority (SCP). SJCE is the City of San José's CCA program, which the San José Community Energy Department administers. Each of the CCAs in the Joint CCAs is located in Northern California, and therefore focus their testimony and participation in this proceeding on issues relevant to Pacific Gas & Electric Company's (PG&E) Application. On June 6, 2022, MCE timely filed a response to PG&E's Application for Approval of its Demand Response Programs, Pilots and Budgets for Program Years 2023-2027 (PG&E Application), and is therefore a party to this proceeding pursuant to Commission Rule 1.4(a)(2). EBCE, PCE, SCP and the City of San José filed motions for party status in this proceeding pursuant to Commission Rule 1.4(a)(4) on April 20, 2023. At the time this testimony was filed, those motions for party status were pending a ruling by the Administrative Law Judge.

I. INTRODUCTION

Demand response (DR) helps reduce the strain that increasingly frequent extreme weather puts on California’s electricity grid. Recognizing that, the Governor’s Office and the California Public Utilities Commission have each taken recent actions to grow the state’s DR resources—including wholesale market-integrated and load-modifying programs. The Joint CCAs view this as an “all-hands-on-deck” moment, during which demand response providers, including community choice aggregators (CCAs), investor-owned utilities (IOUs), and third-party demand response providers (DRPs), must work together to contribute as much demand response resource as possible during times of grid stress.

The Commission can help ensure those efforts are both effective and well-coordinated. To that end, the Joint CCAs support a level playing field between the DR programs administered by CCAs, IOUs, and DRPs. The Joint CCAs also support certain refinements to the design of the DR programs proposed in this proceeding (in particular, the Emergency Load Reduction Program or ELRP), each of which are aimed at maximizing the load reductions delivered by those programs. Finally, the Joint CCAs support transparency with respect to DR program participation, such that the state and each load-serving entity (LSE) have a clear picture of both the forecasted and actual impacts of DR programs.

Below, the Joint CCAs respond to select issues in the January ACR as well as the Energy Division (ED) Staff Proposals based on the Joint CCAs’ priorities and areas of focus.

II. RESPONSES TO QUESTIONS IN JANUARY ACR

Emergency Load Reduction Program (ELRP)

Question 3. What factors should the Commission consider in deciding whether to extend ELRP to 2026 and 2027? Does the status of these factors justify the extension of the pilot program?

The Joint CCAs submit that the Commission should consider two main factors as it evaluates whether to extend ELRP to 2026 and 2027. First, and most importantly, the Commission should consider modifying ELRP to help ensure the program achieves its primary purpose of delivering incremental load reductions (ILR). Second, the Commission should consider transitioning ELRP from a pilot into a permanent program subject to cost-effectiveness rules.

1. The Commission should modify ELRP to increase the ILR it delivers.

The Commission created the ELRP “to allow the large electric IOUs and CAISO to access additional load reduction during times of high grid stress and emergencies involving inadequate market resources, with the goal of avoiding rotating outages while minimizing costs to ratepayers.”² Only ILR—defined as the load reduction achieved during an ELRP event incremental to the non-event applicable baseline and any other existing commitment—is eligible for compensation under the ELRP.³ The fundamental objective of the ELRP, therefore, is to deliver ILR.

The ELRP delivered mixed results in PG&E’s service area in 2022. While the program enrolled approximately 7,000 non-residential customers (ELRP sub-groups A.1 and A.2), 3,750 customers in virtual power plant (VPP) aggregations (ELPR sub-group A.4) and 1.5 million residential customers (ELRP sub-group A.6) in 2022, customer enrollments did not consistently translate to ILR. Based on the Joint CCAs’ review of the *Statewide Residential Emergency Load*

² D.21-03-056 at 18, Finding of Fact 17.

³ *Id.* at 24.

Reduction Program Baseline Evaluation,⁴ *ELRP Data for Summer 2022 Season*,⁵ and the *Draft 2022 ELRP Load Impact Protocol (Draft ELRP LIP)*,⁶ the Joint CCAs submit that the ELRP requires modifications in order to meet its stated goals and deliver ILR going forward.

- a. Auto-enrolling customers in the Residential ELRP (sub-group A.6) has not resulted in ILR and should be ceased.*

The Draft ELRP LIP finds that residential customer auto-enrollment under ELRP sub-group A.6 did not drive meaningful ILR. It states: “The analysis of load reductions for A.6 residential enrollment status (CARE auto-enrolled, FERA auto-enrolled, HER auto-enrolled, and self-enrolled), found that the reported ex post impacts for the auto-enrolled sub-groups were largely Flex Alert impacts with no or very little incremental ELRP load reduction.”⁷ In contrast, “self-enrolled ELRP participants . . . reduced their reference baseline load by an average of 10.4% during ELRP event hours and approximately 70% of the average load reduction was incremental ELRP impacts.”⁸ The Draft ELRP LIP therefore recommends:

- “Program managers should attempt to increase the number of self-enrolled ELRP participants to increase the ELRP incremental load reduction” and;
- “If the goal of the ELRP is to compensate customers for incremental load reduction, then ELRP should consider discontinuing auto-enrollment of customers.”⁹

Indeed, as described above, the fundamental objective of the ELRP is to deliver ILR.¹⁰ The Joint CCAs therefore strongly agree with the Draft ELRP LIP’s recommendation that the Commission should encourage self-enrollment and cease auto-enrollment in the residential ELRP.

⁴ Demand Side Analytics, *Statewide Residential Emergency Load Reduction Program Baseline Evaluation* (Jan. 2023).

⁵ See Attachment A to Administrative Law Judge’s Ruling Providing the Emergency Load Reduction Program Data for 2022 Summer Season (Mar. 2, 2023).

⁶ Verdant Associates, *Draft PG&E 2022 ELRP (Emergency Load Reduction Program) Load Impact Report* (Mar. 10, 2023).

⁷ Draft ELRP LIP at 119.

⁸ *Id.*

⁹ *Id.*

¹⁰ D.21-03-056 at 18.

To the extent the Commission permits any level of auto-enrollment in the residential ELRP going forward, it should cease the auto-enrollment of Equity customers (i.e., customers enrolled in the California Alternate Rates for Energy (CARE) or the Family Electric Rate Assistance (FERA) programs), and instead focus auto-enrollment on high usage customers and sectors (such as residential customers with devices with high usage patterns like pool pumps, or sectors that have modifiable load like agricultural pumping).

The Joint CCAs have previously explained other reasons why auto-enrollment in the ELRP is neither consistent with sound policy nor rational program design (beyond its failure to result in meaningful impacts).¹¹ Whereas D.16-09-056 established that “utilities and third-party providers should fairly compete on a level playing field to vie for customers to enroll in their demand response programs”,¹² auto-enrollment tilts the DR landscape towards the IOU and undermines the CCAs’ efforts to efficiently enroll customers in their DR programs.¹³ For similar reasons, auto-enrollment stifles innovation by DR program administrators because it may constrain customer opportunities to participate in CCA programs that offer higher impact and higher rewards.¹⁴ Finally, auto-enrollment invites implementation challenges and customer confusion. Even where customers technically have the option of unenrolling from one DR program in order to enroll in another more rewarding or impactful DR program, the unenrollment process can be particularly burdensome and challenging where the customer *did not even know* they had been enrolled in a DR program in the first place.¹⁵

¹¹ See, e.g. R.20-11-003, MCE Opening Brief at 28-32 (Sept. 10, 2021).

¹² D.16-09-056 at 52.

¹³ See Prepared Direct Testimony of Joint Community Choice Aggregators at 8 (Apr. 21, 2023) (describing the challenge of enrolling customers in CCA DR programs while avoiding dual participation violations, particularly in light of PG&E’s auto-enrollment of residential customers into the Residential ELRP).

¹⁴ Again, see Prepared Direct Testimony of Joint Community Choice Aggregators at 8 (Apr. 21, 2023).

¹⁵ See R.20-11-003, OhmConnect Phase I Reply Testimony at 5:20-21.

CCA DR programs, in contrast, do not auto-enroll customers. MCE’s Peak FLEXmarket program, for example, has successfully enrolled customers without relying on auto-enrollment—it enrolled 1,284 customers in 2021 and 2,264 customers in 2022. The Joint CCAs note, however, that simply enrolling customers is not sufficient to deliver ILR; enrolled customers must understand how to *effectively participate* in DR programs. Unlike technology incentive programs that reward customers for simply installing equipment (such as energy storage systems under the Self Generation Incentive Program (SGIP) or traditional energy efficiency (EE) programs), DR programs require that program participants take specific actions, or modify their baseline behavior in specific ways, during specific windows of time (for example, not running their dishwasher during peak hours). In other words, they require far more *engagement* from the customer. In order for an enrolled customer to participate effectively in a DR program, program administrators must help familiarize them with the program, and help those customers understand (1) how to reduce demand; (2) when they may be asked to do so; and (3) why reducing demand can benefit the grid, among other things.

b. Batteries participating in the ELRP’s Virtual Power Plant (sub-group A.4) should not be permitted to charge during event windows.

The Draft ELRP LIP finds that batteries participating in the ELRP’s VPP (sub-group A.4) fully curtailed load for a maximum of 2 hours.¹⁶ In other words, the aggregator discharged all, or nearly all, participant batteries during a 2 hour period.¹⁷ This means that during early and late event hours, many participating batteries started charging and hence *increased* grid stress, likely during times when load reductions were most needed (i.e. the net peak period).¹⁸ This reduced the average hourly ILR that sub-group A.4 delivered. As the ELRP currently only considers load reductions

¹⁶ Draft ELRP LIP at 119.

¹⁷ *Id.*

¹⁸ *Id.*

and not load increases during event hours for purposes of calculating ILR (see the Joint CCAs’ responses to Energy Division Staff Proposal B, below, for further discussion on this issue), the true load reduction impact of batteries is being overstated by the current program reports.

To remedy this issue, the Draft ELRP LIP recommends that the Commission work with VPP aggregators to discourage charging of batteries during events, and/or shorten event windows to strategically target two to three hours of the five-hour resource adequacy (RA) window.¹⁹ If load reduction is needed over a longer duration, the Draft ELRP LIP recommends that PG&E work with VPP aggregators to “distribute the battery discharge over the duration of the event window.”²⁰ The Joint CCAs support this recommendation, but recommend that the Commission go a step further, and expressly prohibit charging by participating batteries during ELRP event hours. Moreover, in order to better evaluate this issue, the Commission should direct the IOUs and the participating aggregator to explain when batteries were charged and discharged during each event in 2022, and provide a narrative explanation of why batteries charged during event hours.

- c. Non-residential participants in ELRP sub-groups A.1 and A.2 should only be compensated if they deliver a minimum percentage of their nominated capacity.*

The Draft ELRP LIP finds that non-residential participant nominations in sub-group A.1 were greatly overstated compared to actual ex-post ILR.²¹ Indeed, only 21 MW out of the 400 MW of nominated capacity participated in events in 2022. The Draft ELRP LIP attributes this massive discrepancy to the fact that the ELRP does not include a mechanism that holds participants to their nominated load reductions (in other words, there is no penalty provision).²² It recommends that

¹⁹ *Id.*
²⁰ *Id.*
²¹ *Id.*
²² *Id.*

the Commission use actual load impacts, and not nominated capacity, to set expectations for future years.

The Joint CCAs agree that the discrepancy between nominated capacity and actual ILR is cause for concern. Where a DR program forecasts 400 MW of nominated capacity, but only 21 MW ultimately participate in events, 380 MW of non-participating capacity are effectively “left on the table”—that capacity neither participated in the ELRP nor could it participate in other DR programs due to dual participation restrictions. In order to narrow this gap, and promote a higher ratio of participating to nominated capacity, the Joint CCAs recommend that the Commission establish a participation floor (expressed as a percentage of nominated capacity) tied to compensation, and compensate only those customers whose participation levels surpassed that floor.

d. The Commission should promote clarity around the measurement methods applied to ELRP sub-groups.

The measurement and verification (M&V) methods applied to the ELRP are neither clear nor consistent—PG&E has not sufficiently explained whether it uses device-level or meter-level measurement to measure ILR for the various ELRP sub-groups. It is the Joint CCAs’ understanding that in the context of sub-group A.4 (VPP aggregators) and A.5 (EV and VGI aggregators), ILR is determined (and customers are compensated) based on measurements at the device-level, but the M&V approach applied to other sub-groups is less clear. This matters, because the two measurement approaches can lead to very different results.

Assuming that device-level measurement is indeed used for sub-groups A.4 and A.5, a customer participating with a battery resource in the A.4 sub-group would be compensated for their ILR based on the kWhs that the system discharged to the home or grid, irrespective of whether actual ILR were measured at the customer’s meter. That means, under a device-level measurement

approach, the participating battery that discharges to the home or grid would be paid by the ELRP program for the load reduction, even if the load of the property on which the battery is located *increased* over the same period of time (i.e., the air conditioner was on). Under the same set of facts, a meter-level measurement approach would not show a load reduction, and the customer would not be paid. The contrasting outcomes between meter- and device-level measurement become more complicated as customers add multiple participating devices. Consider a customer with a battery, smart thermostat, heat pump and an EV: meter-level measurements of load reductions using whole-home interval data will likely yield vastly different results as compared to the sum of device-level measurements.

PG&E's ELRP Data for the Summer 2022 Season further illustrates the lack of clarity associated with ELRP measurement. That report acknowledges that the ELRP data:

“represent the outcomes of different hypothetical baseline and settlement calculation methods for Incremental Load Reduction and compensation for program participants. Only Column E (Total Delivered kWh (Interval Positive Performance)) and Column D (Total Delivered kWh (Event Net Positive Performance)) represent methods used by PG&E in 2022 for subgroups A1-A5 and subgroup A6, respectively. None of these calculation methods are appropriate to use as a proxy for load impacts for the ELRP program. For an estimate of load impacts, please refer the draft results of PG&E's ELRP Load Impact Study that will be released in March 2023.”²³

The various calculation methods used to evaluate ILR, determine compensation, and determine load impacts make it challenging for stakeholders to assess the impacts of the ELRP and contrast its impact to other DR programs. The Joint CCAs therefore submit the Commission and DR providers (IOUs, CCAs and DRPs) should strive to apply a consistent measurement approach (device-level versus meter-level) across DR programs, to the extent feasible, even if

²³ See Attachment A to Administrative Law Judge's Ruling Providing the Emergency Load Reduction Program Data for 2022 Summer Season (Mar. 2, 2023).

specific baseline and M&V methodologies vary. To be clear: the Joint CCAs are not fundamentally opposed to the use of device-level measurement (or any other method) for DR program compensation and M&V purposes. Rather, the Joint CCAs support clarity regarding the M&V approach applied to each DR program, such that the Commission and all stakeholders are better able to understand and benchmark the performance of each program, and make apples-to-apples comparisons.

To that end, the Joint CCAs recommend that the Commission direct the IOUs to clearly and simply outline the performance of the ELRP sub-groups both in terms of performance at the device- and at the meter-level so that parties can get a better sense of the true impacts of the ELRP. Following an opportunity for comment on those results, the Commission should issue a ruling addressing the appropriate measurement method for each ELRP sub-group.

2. The Commission should consider transitioning ELRP from a pilot into a program subject to cost-effectiveness rules.

The Commission authorized the ELRP as a pilot program through 2025.²⁴ As a pilot, ELRP is not subject to the cost-effectiveness requirements described in the DR Cost-Effectiveness Protocols.²⁵ The Joint CCAs recommend that, to the extent the Commission decides to extend the ELRP into 2026 and 2027, it should no longer be designated a pilot. Pilots are used to test program design on a small scale before those programs are rolled out to a broader set of customers. ELRP, in contrast, will constitute over half of PG&E's DR budget in program years 2024-2027 (\$426

²⁴ D.21-03-056 at 19.

²⁵ In D.21-03-056, the Commission found that “[w]aiving the use of our traditional cost-effectiveness tools for all demand response proposals that are adopted in this decision for years 2021 and 2022 will allow for increased participation.” D.21-03-056, Finding of Fact 35 (Mar. 26, 2021). Accordingly, the Commission waived the use of traditional cost-effectiveness tools for the ELRP in 2021 and 2022. D.21-03-056 at 29. In D.21-02-015, the Commission waived the use of traditional cost-effectiveness tools for the ELRP in 2023. D.21-12-015 at 63. *See also* D.15-11-042 at 72 (reiterating that pilot programs are not subject to a cost-effectiveness analysis under the DR Cost-Effectiveness Protocols).

million out of a total \$791 million).²⁶ A program of that scale should be rigorously tested for cost-effectiveness. To the extent the ELRP is *not* cost-effective, either the Commission should not extend the program as a whole beyond 2025, or it should only extend those sub-groups that are cost-effective.

MISCELLANEOUS

Question 11: Currently, some aspects of Rule 24/32 are applicable only when DR providers aggregate bundled customers. Should these Rules be expanded to include DRPs' aggregation of unbundled customers? If so, how should these Rules be revised?

At a conceptual level, the Joint CCAs agree with the notion that the provisions in Rule 24/32 should apply both when DR providers aggregate bundled customers as well as when they aggregate unbundled customers for the purpose of CAISO market-integrated, IOU-administered DR programs. It is the Joint CCAs' understanding that both IOUs and third-party DR providers already enroll both bundled and unbundled customers in their CAISO market-integrated DR programs. The Joint CCAs are supportive of a consistent set of rules being applied to all customers participating in the same program, but recommend that the Commission require IOUs provide the service list a redline describing proposed revisions to Rule 24/32 and allow parties an opportunity to comment. A redlined rule would allow a more robust discussion of the impact of those revisions on DR providers, bundled and unbundled customers, and LSEs. It would also allow parties to more comprehensively consider necessary revisions to the Rule.

For instance, the Joint CCAs observe that Rule 24/32 requires clarification in order to better define the role of LSEs with respect to CAISO market-integrated, IOU-administered DR programs. Section D.1.a. of PG&E's Rule 24 for example, which specifies the data that PG&E must transmit to a Non-Utility DRP, includes the following: "Unique Customer Identifier to track the customer

²⁶ PG&E Application at 20-21.

Service Agreement in CAISO Relevant Systems. This information will be provided to the customer’s Load Serving Entity (LSE) too if different from PG&E.” The Joint CCAs posit that the LSE should also know (1) which program the resource is enrolled in, and (2) the resource’s nominated capacity. As described in more detail in the Joint CCAs’ Intervenor Testimony, this information is integral for both load forecasting and to avoid dual enrollment in DR programs.²⁷ To comprehensively address changes that may be necessary to the provisions of Rule 24/32 (including changes to define the role of the LSE), the Joint CCAs support a workshop dedicated to this issue.

III. RESPONSES TO ENERGY DIVISION STAFF PROPOSALS

A. **The Commission Should Adopt Energy Division Staff Proposal B, and count all negative and positive ILRs during ELRP events for the purpose of determining compensation.**

Energy Division (ED) staff observes that the IOUs’ calculation of ILR for Group A (customers not participating in DR programs) ignores negative incremental load reduction (i.e., load increases) during ELRP events.²⁸ ED proposes an alternative calculation methodology (Method 2) for determining a customer’s ILR. Under Method 2, all positive and negative hourly ILRs during an ELRP event are counted and summed in order to determine if the total event ILR was positive or negative. Customers would only receive compensation if the total event ILR were positive (i.e., if the customer actually achieved incremental load reductions, after considering all load increases and reductions occurring during the event).²⁹ The table below contrasts the IOUs’ calculation method with ED’s proposed Method 2, and the resulting ILR under each method.

²⁷ See Prepared Direct Testimony of Joint Community Choice Aggregators at 7-8 (Apr. 21, 2023).

²⁸ Appendix A to January ACR at 4. The Joint CCAs note that the IOUs have filed supplemental advice letters Advice 4950-E-A (Southern California Edison), 6826-E-A (PG&E) and 4142-E-A (San Diego Gas and Electric Company) to voluntarily modify their ILR methodology for ELRP sub-group A participants and align with ED Staff Proposal B. The Commission has issued Draft Resolution E-5267 addressing and approving those modifications.

²⁹ *Id.*

Table 1: ILR Measured under IOU Method and ED Proposed Method

Event	Measured Hourly ILR	ILR Method 1 (IOUs)	ILR Method 2 (ED)
Hour 1:	+2	+2	+2
Hour 2	+2	+2	+2
Hour 3	-3	0	-3
Event ILR		+4	+1

The Joint CCAs strongly endorse ED Staff’s proposed Method 2, for each of the reasons ED lists under Proposal B.³⁰ Moreover, Method 2 is consistent with the way in which the Joint CCAs calculate load reductions associated with their DR programs. By only counting load reductions, and not load increases, during an ELRP event, IOUs significantly overstate actual ILR achieved. Table 2 below illustrates the gulf between “unadjusted” load reductions that count both load increases and decreases during the ELRP event (Method 2) and “adjusted” load reductions that zero out load increases (the IOUs’ methodology) at the sub-group level.³¹

³⁰ *Id.* at 5-6.

³¹ The Joint CCAs compiled the data presented in the table based on the report “PG&E ELRP Event ILR” provided as Attachment A to Administrative Law Judge’s Ruling Providing the Emergency Load Reduction Program Data for 2022 Summer Season (Mar. 2, 2023). As described in the report, PG&E uses different methods of performance adjustments for the different ELRP sub-groups.

Table 2: Difference Between Adjusted and Unadjusted Performance at the Program Level³²

Sub-group	Unadjusted Delivered kWh	Adjusted Net Positive Performance (kWh)	Difference (%)
A.1 (non-BIP)	1,058,873	2,620,600	247%
A.1 (BIP)	5,993	6,848	114%
A.2 (BIP)	(14,440)	1,840	
A.4	354,181	398,509	113%
A.6 PSR	12,890,520	29,124,979	226%
Total	14,295,128	32,021,108	224%

The Joint CCAs therefore recommend that the Commission adopt Energy Division Staff Proposal B such that the IOUs more accurately determine the ILR associated with Group A customers going forward.

B. The Commission should adopt Energy Division Staff Proposal D, but clarify that the Proposal’s definition of “Qualified” DR Programs applies irrespective of whether the DR program administrator is a CCA, an IOU or a third-party DRP.

PG&E has proposed that the Commission develop DR enrollment requirements for customers receiving ratepayer-funded technology incentives, such as Energy Efficiency (EE) and Distributed Generation.³³ In R.20-05-012, the Commission acted in part on this issue, and required that customers receiving rebates for Heat Pump Water Heater (HPWH) appliances via the Self Generation Incentive Program (SGIP) enroll in a “qualified” DR program for a minimum of three years.³⁴ ED Staff anticipates that the Commission may establish similar requirements in other DER proceedings in the future. With that in mind, ED Staff proposes to define “qualified” DR programs

³² The Joint CCAs do not include the percentage difference between unadjusted and adjusted kWhs for the A.2 sub-group as it is not intuitive due to the negative performance (or load increase) when measured with the unadjusted methodology.

³³ PG&E Direct Testimony, Exhibit PGE-2 at 2-11, 1-14.

³⁴ D.22-04-036 at 105-108.

eligible to meet a DR program enrollment requirement as a condition of a customer receiving an incentive or rebate as any of the following:

- i. Supply-side market-integrated DR programs counted for Resource Adequacy.
- ii. Load modifying DR programs integrated with CEC's peak demand forecasting process (such as Critical Peak Pricing rates offered by the IOUs, and potentially marginal-cost-based dynamic pricing rates should the Commission adopt such rates in the future and establish a process to integrate those rates with CEC's forecasting process).
- iii. Any DR pilot authorized and designated by the Commission as a "qualified" DR program eligible to meet the DR enrollment requirement

The Joint CCAs support ED's Proposal D. However, in the interest of promoting customer choice and flexibility, the Joint CCAs recommend the Commission clarify that the above definition applies irrespective of whether the DR program administrator is an IOU, a CCA, or a third-party DRP. To that end, the Joint CCAs propose the following modifications to ED's proposed definition of a "qualified" DR program:

- i. Supply-side market-integrated DR programs counted for Resource Adequacy, irrespective of whether the program administrator is an IOU, a CCA or a third-party DRP.
- ii. Load modifying DR programs integrated with CEC's peak demand forecasting process (such as Critical Peak Pricing rates offered by the IOUs, and potentially marginal-cost-based dynamic pricing rates should the Commission adopt such rates in the future and establish a process to integrate those rates with CEC's forecasting process), irrespective of whether the program administrator is an IOU, a CCA or a third-party DRP.
- iii. Any DR pilot authorized and designated by the Commission as a "qualified" DR program eligible to meet the DR enrollment requirement, irrespective of whether the program administrator is an IOU, a CCA or a third-party DRP.

While the Joint CCAs support the adoption of ED Staff Proposal D with the modifications described above, the Joint CCAs continue to have implementation-related concerns with PG&E's

proposal. MCE expressed those concerns in its response to PG&E's Application,³⁵ and the Joint CCAs will not rehash those concerns in their entirety here. Briefly, to the extent the Commission adopts PG&E's proposal, program administrators will have to determine:

- How program impacts (e.g., energy savings, demand savings, and others) will be measured and assigned between programs. For instance, if a customer enrolls in a peak demand focused EE program, and is required as a result to enroll in a DR program, the incrementality rules applied to energy savings and demand reductions during peak hours will require clarification.
- How the potentially conflicting goals of technology incentive and DR programs will be reconciled. For instance, whereas a DR program may prioritize peak demand reduction, a technology incentive program, such as SGIP, may prioritize GHG reduction.

The Joint CCAs continue to recommend that the Commission carefully consider the implementation challenges associated with requiring that customers receiving ratepayer-funded technology incentives enroll in DR programs.

IV. CONCLUSION

The Joint CCAs appreciate this opportunity to provide responses to the questions posed in the January ACR and to the issues outlined in the ED staff proposal. The Joint CCAs request that the Commission adopt the recommendations described herein, and listed again below:

- The Commission should encourage self-enrollment and cease auto-enrollment in the residential Emergency Load Reduction Program (ELRP sub-group A.6);
- To the extent the Commission permits any level of auto-enrollment in the residential ELRP going forward, it should cease the auto-enrollment of Equity customers (i.e., customers enrolled in the CARE or the FERA programs), and instead focus auto-enrollment on high usage customers and sectors (such as residential customers with devices with high usage patterns like pool pumps, or sectors that have modifiable load like agricultural pumping);
- The Commission should prohibit charging by participating batteries in sub-group A.4 during ELRP event hours. Moreover, in order to better evaluate this issue, the Commission should direct the IOUs and the participating aggregator to explain when batteries were charged and discharged during each event in 2022, and provide a narrative explanation of why batteries charged during event hours;

³⁵ A.22-05-002 et al., MCE Response to the Application of Pacific Gas and Electric Company for Approval of its Demand Response Programs, Pilots and Budgets for Program Years 2023-2027 at 8-10 (June 6, 2022).

- For non-residential customers participating in ELRP sub-groups A.1 and A.2, the Commission should establish a participation floor (expressed as a percentage of nominated capacity) tied to compensation, and compensate only those customers whose participation levels surpassed that floor;
- The Commission should direct the IOUs to clearly and simply outline the performance of the ELRP sub-groups both in terms of performance at the device- and at the meter-level so that parties can get a better sense of the true impacts of the ELRP. Following an opportunity for comment on those results, the Commission should issue a ruling addressing the appropriate measurement and compensation method for each ELRP sub-group;
- To the extent the Commission decides to extend the ELRP into 2026 and 2027, it should no longer be designated a pilot;
- The Commission should require IOUs provide the service list a redline describing proposed revisions to Rule 24/32 and allow parties an opportunity to comment. Further, to comprehensively address changes that may be necessary to the provisions of Rule 24/32 (including changes to define the role of the LSE), the Joint CCAs support a workshop dedicated to this issue;
- The Commission should adopt Energy Division Staff Proposal B, and;
- The Commission should adopt Energy Division Staff Proposal D, with the following modifications to ED’s proposed definition of a “qualified” DR program:
 - Supply-side market-integrated DR programs counted for Resource Adequacy, irrespective of whether the program administrator is an IOU, a CCA or a third-party DRP.
 - Load modifying DR programs integrated with CEC’s peak demand forecasting process (such as Critical Peak Pricing rates offered by the IOUs, and potentially marginal-cost-based dynamic pricing rates should the Commission adopt such rates in the future and establish a process to integrate those rates with CEC’s forecasting process), irrespective of whether the program administrator is an IOU, a CCA or a third-party DRP.
 - Any DR pilot authorized and designated by the Commission as a “qualified” DR program eligible to meet the DR enrollment requirement, irrespective of whether the program administrator is an IOU, a CCA or a third-party DRP.

Respectfully submitted,



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*On behalf of Joint Community Choice
Aggregators*

Dated: April 21, 2023



Comments on Draft revised final proposal

Initiative: Day-ahead market enhancements

Comment period

Apr 06, 2023, 03:00 pm - Apr 24, 2023, 05:00 pm

Submitting organizations

California Community Choice Association

California Community Choice Association

Submitted on 04/25/2023, 02:42 pm

Contact

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

1. Please provide your organization's feedback on the changes made to the Day-Ahead Market Enhancements final proposal:

The California Community Choice Association (CalCCA) appreciates the California Independent System Operator (ISO) including the Resource Adequacy (RA) true-up mechanism and storage Residual Unit Commitment (RUC) participation rules in the Revised Final Proposal. CalCCA supports the RA true-up mechanism and proposes a modified process for its sunset. CalCCA also generally supports the RUC participation rules but requests clarification regarding RA and non-RA bidding obligations and how the multipliers in the envelope equations will be determined.

The Revised Final Proposal includes a settlement mechanism that would allow contracting parties to opt-in to a RA capacity true-up in which the ISO will compensate the load-serving entity for opt-in RA capacity at the respective imbalance reserve capacity price (minus opportunity costs) and/or reliability capacity price. The ISO is proposing this as a transitional mechanism that would be in place for three years to allow time for existing contracts to roll off or be renegotiated. CalCCA supports the ISO's proposed RA true-up mechanism, but recommends the ISO modify the three-year sunset date, given existing contracts may be long term, and expire later than three years into the future. Renegotiating contracts could result in increased costs given the constrained RA market.[\[1\]](#)

CalCCA recommends the following process for sunsetting the RA true-up mechanism:

The ISO implements the RA true-up functionality and keeps it in place for at least three years (e.g. 2025, 2026, and 2027 assuming a Fall 2024 implementation). After three years, if no market participant uses the functionality for one full year (e.g., no market participant uses it in 2028), the ISO would notify market participants of its intent to retire the functionality. The ISO would give market participants an opportunity to demonstrate that they will use the functionality in the upcoming year (e.g., in 2029) and if no party can demonstrate they will use it within the next year, the ISO would then remove the functionality.

The Revised Final Proposal also proposes allowing storage resources to participate in the RUC process. CalCCA supports this proposal. As storage resources become a larger and larger portion of the resource mix, barring storage from participating in RUC could cause market inefficiencies. The last bullet on slide 12 from the April 17, 2023 workshop seems to imply that the ISO would require RA and non-RA storage resource participation in RUC.^[2] The ISO should clarify in its proposal that RA storage will be required to participate in RUC, while non-RA storage will have the ability to participate in RUC but not be required to participate in RUC. This maintains the current RUC bidding requirements that only require participation from RA resources.

During the April 17, 2023, workshop, the ISO presented how it will use envelope constraints to ensure RUC awards do not impact state-of-charge given storage cannot provide RUC capacity without state-of-charge. The ISO's proposal to use envelope equations to prevent RUC awards that are inconsistent with actual state-of-charge or the upper/lower bounds from the envelope equations could be effective at ensuring storage can deliver on its RUC awards and other awards. More discussion is needed, however, on how the ISO will set the multipliers in the envelope equations that will be used to estimate how much imbalance reserve capacity will be converted into energy and therefore impact state-of-charge. CalCCA requests additional discussion in the revised final proposal outlining how the ISO will choose to set the multiplier values and the impacts of any inconsistencies with setting the multiplier less than one and the nodal imbalance reserve design.

^[1] The California Public Utilities Commission's *2021 Resource Adequacy Report (Mar. 2023)* demonstrates the tightness in the RA market causing increased costs: "The weighted average price of system RA for both seasons has increased each year, and at an accelerating pace. Average August prices were \$3.13/kW-month in 2017 but increased each year thereafter. By 2021 the average price had risen to \$8.07 kW/month, an increase of 158 percent over just 5 years." https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2021_ra_report.pdf. Counterparties will be unlikely to renegotiate long term contracts to account for new revenue streams from ISO capacity payments as RA prices continue to increase dramatically – the result will be increased overall costs.

^[2] See <http://www.caiso.com/InitiativeDocuments/Presentation-Day-AheadMarketEnhancements-Apr17-2023.pdf>.



Comments on Final proposal and draft Tariff language

Initiative: Interconnection process enhancements 2023

Comment period

Apr 14, 2023, 08:00 am - Apr 24, 2023, 11:00 pm

Submitting organizations

California Community Choice Association

California Community Choice Association

Submitted on 04/24/2023, 01:44 pm

Contact

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

1. Please share your organization's overall position on the final proposal:

The California Community Choice Association (CalCCA) appreciates the opportunity to comment on the California Independent System Operator's (ISO) Interconnection Process Enhancements 2023 Final Proposal. This initiative is coming at a critical time when the entire industry is moving as quickly as possible to get new clean resources online. CalCCA's comments on the Issue Paper/Straw Proposal highlight the urgent need to interconnect resources at an unprecedented pace to meet California's ambitious climate goals.[\[1\]](#)

Track One focuses on near-term schedule changes delaying the study of new interconnection requests. While it is unfortunate to delay the interconnection process at a time when the need for new resource interconnection is at its highest, CalCCA understands the ISO's need to delay the study of Cluster 15 interconnection requests, given the record amount of requests moving from Phase I to Phase II. CalCCA anticipates that Track Two of this initiative will bring about the "significant and transformative improvements"[\[2\]](#) the ISO seeks. In Track Two, the ISO must consider policies that will allow the ISO to support the number of requests the ISO has experienced in Cluster 14 and anticipates in Cluster 15 going forward. The amount of build-out projected by the California Energy Commission in its Senate Bill (SB) 100 scenarios and planned for in the ISO's Transmission Plan will necessitate efficient queue management that supports the magnitude of requests in Cluster 14 without further delays and supports fluctuating queue sizes year over year.

The following Track One proposals appear reasonable given the delay between when Cluster 15 interconnection requests were submitted (April 2023) and when the ISO will begin validating those requests (April 2024):

Allowing interconnection customers that withdraw prior to April 1, 2024 to receive a refund of any portion of the interconnection customer's study deposit that exceeds costs that the ISO, Participating Transmission Owners, and third parties have incurred on the interconnection

customer's behalf (which the ISO expects to be minimal); and

Allowing the interconnection customer to make certain modifications to their request, including changing the technology type, changing the megawatt amounts of the various generator technologies or adding battery storage as long as the original interconnection capacity in the request does not increase, or changing the point of interconnection within the same study area, before their request is validated (by Sept. 2024).

CalCCA also supports the ISO's determination to not provide a special schedule for offshore and out-of-state wind. Offshore and out-of-state wind resources can play important roles in meeting state policy goals. As stated in CalCCA's opening comments, however, CalCCA would be concerned with using a special study schedule for offshore and out-of-state wind if it would impact the study schedule of Cluster 15, and therefore, delay the interconnection of other projects needed to meet procurement orders. CalCCA agrees with the ISO that because policy-driven transmission projects for offshore wind and out-of-state wind are expected to be included in the 2023-2024 Transmission Planning Process cycle, studying offshore wind and out-of-state wind in Cluster 15 with the other projects makes the most sense.

[1] CalCCA Comments on the Issue Paper Straw Proposal: "From 2001 through 2021, the state has built new capacity at a rate of 1,308 MW per year. Under the SB 100 Core Scenario, the rate will need to increase to 7,292 MW per year from 2022 through 2045 (a 557 percent increase)." <https://stakeholdercenter.caiso.com/Comments/AllComments/b6ed131c-ecaa-460d-8316-e0e0dcd0373f#org-7f69761d-1e42-4add-9794-d8d20a05431d>.

[2] Final Proposal at 1.

2. Please provide a summary of your organization's comments on the draft Tariff language.

CalCCA has no comments on the draft tariff language at this time. The language appears consistent with the policy in the Final Proposal.



Comments on draft transmission plan

2022-2023 Transmission planning process

Comment period

Apr 11, 2023, 06:30 pm - Apr 25, 2023, 05:00 pm

Submitting organizations

Marin Clean Energy

Marin Clean Energy

Submitted on 04/25/2023, 01:54 pm

Contact

MCE Regulatory (regulatory@mcecleanenergy.org)

1. Please provide your organization's overall comments on the Draft 2022-2023 Transmission Plan April 11, 2023 stakeholder call discussion.

Marin Clean Energy (MCE) thanks and commends the California Independent System Operator (CAISO) for its extensive work dedicated to developing the Draft 2022-2023 Transmission Plan and the careful focus on laying the essential groundwork for California to aggressively progress towards achieving its clean energy and reliability needs. In support of these efforts, MCE's comments on the Draft Transmission Plan specifically address elements of the Draft Transmission Plan's Policy-Driven Need Assessment and the Economic Planning Study.

With regard to the Policy-Driven Need Assessment, MCE encourages the CAISO to include an additional scenario covering the hours of highest solar production to maximize and optimize solar generation's ability to charge energy storage assets.

With regard to the Economic Planning Study, MCE encourages the CAISO take a number of specific actions, described in more detail in Prompt 5, below, that MCE understands will unlock the feasibility and net benefits associated with Alternatives 2, 3, 4, & 5.

2. Provide your organization's comments on chapter 1 Overview of the Transmission Planning Process.

MCE provides no comments in response to this prompt at this time.

3. Provide your organization's comments on chapter 2 Reliability Assessment.

MCE provides no comments in response to this prompt at this time.

4. Provide your organization's comments on chapter 3 Policy-Driven Need Assessment.

MCE Recommendation: Modify the Policy-Driven Need Assessment to include a scenario that covers the hours of highest solar production to maximize and optimize solar generation's ability to support energy storage charging and serving load.

Discussion: The Policy-Driven Need Assessment has two objectives: (1) to support Resource Adequacy (RA) deliverability status for the renewable generation and energy storage resources identified in the portfolio as requiring that status; and (2) to support the economic delivery of renewable energy during all hours of the year. MCE's understanding is that the study uses the same system need scenarios as the reliability assessment, which are: (1) Highest System Need ("HSN", HE19-HE22 summer); and (2) Secondary System Need ("SSN", HE15-HE18 summer). MCE is concerned that the scenarios underestimate the contribution of solar resources to transmission flows in hours outside of the highest and secondary system needs, which is inconsistent with the second objective of the Policy-Driven Need Assessment.

MCE urges the CAISO to consider modifying the Policy-Driven Need Assessment to include a scenario that covers the hours of highest solar production. Including such a scenario will ensure that solar production can be maximized to support energy storage charging and serving load with carbon free solar generation to meet the electrification goals of other sectors of the economy, such as transportation.

5. Provide your organization's comments on chapter 4 Economic Planning Study.

MCE Recommendation:

Update the base case in the Economic Planning Study for the PG&E Panoche/Oro Loma area to have the disconnect switch at Firebaugh in the open position from April through October (and possibly through November);

Re-evaluate the SPS impact on the Oro Loma – Poso 70 kV congestion with the Firebaugh switch position corrected;

Publish the economic benefit results for Alternative 2;

Re-evaluate the economic benefits for each Alternative with the Firebaugh switch position corrected; and

Further clarify how CAISO determined that the reconductoring work described in Alternative 3 costs \$173,000,000 (MCE provides further explanation of this issue in Subsection D, below).

Discussion: The base case CAISO used in its Economic Planning Study for the PG&E Panoche/Oro Loma area is incongruous with the existing and planned day-to-day operating situation in the area. This incorrect modeling led CAISO to improperly conclude that (a) Alternative 2, using the Remedial Action Scheme (RAS), causes reliability issues, and (b) all Alternatives do not provide net benefits. When the appropriate base case is used, however, the study will show that all alternatives provide net benefits. Moreover, it will show that Alternative 2 (using the RAS) also

provides reliability benefits. Therefore, MCE recommends the CAISO report the economic benefit results of Alternative 2.

As stated above, to improve the Economic Planning Study, MCE requests CAISO take the following actions to ensure that the study appropriately reflects the existing and planned day-to-day operating situation in the PG&E Panoche/Oro Loma area:

Update the base case in the Economic Planning Study for the PG&E Panoche/Oro Loma area to have the disconnect switch at Firebaugh in the open position from April through October (and possibly through November);

Re-evaluate the SPS impact on the Oro Loma – Poso 70 kV congestion with the Firebaugh switch position corrected;

Publish the economic benefit results for Alternative 2;

Re-evaluate the economic benefits for each Alternative with the Firebaugh switch position corrected; and

Further clarify how CAISO determined that the reconductoring work described in Alternative 3 costs \$173,000,000 (MCE provides further explanation of this issue in Subsection D, below).

By taking the aforementioned actions, MCE's analysis indicates the economic planning study will yield the following results in the PG&E Panoche/Oro Loma area:

Alternative 2 is shown to not cause reliability issues, and therefore is a feasible solution;

Alternatives 2, 3, 4, and 5 provide positive net benefits; and

At a minimum, Alternatives 2 and 3 provide positive net benefits that justify the implementation cost.

A. The Firebaugh disconnect switch needs to be modeled in the open position from April through October (and possibly through November).

PG&E adjusts disconnect switch positions throughout the year in what it calls “summer setups” to achieve local system reliability and load serving. CAISO's base case appropriately recognizes PG&E's use of summer setup on the lines of the two 70 kV corridors in the PG&E Panoche/Oro Loma area. However, the period in which it modeled the 70 kV corridor between Oro Loma and Mendota as open was much shorter than the historical and planned period (modeled one month rather than seven months). This modeling error significantly impacts the results of the analysis and needs to be corrected.

PG&E regularly operates with the disconnect switch at the Firebaugh substation open for the entire summer. With this disconnect switch open, the 70 kV corridor between Oro Loma and Mendota is open. According to Transmission Outage Reports from 2022, the Firebaugh disconnect switch was open from May through October 2022.^[1] Also, according to recent Transmission Outage Reports, PG&E plans to operate with the Firebaugh disconnect switch open from May through December 2023.^[2] PG&E also now refers to this open position as “new normal open.” The study needs to reflect this “new normal open” switch positioning in its base case to more accurately reflect the benefits of Alternatives 2, 3, 4, & 5.

B. A RAS that trips local solar generation under the contingency condition is a feasible solution and therefore needs to be considered.

With the corrected Firebaugh disconnect switch position discussed above, the RAS solution that CAISO describes in the study cannot cause the Oro Loma – Poso 70 kV overloads because the location of the tripped generation and remaining load is isolated from the identified overloaded path.

CAISO relies on its results in Table G.10-15 to support its conclusion that the RAS solution is infeasible. It shows that the occurrences of congestion on Oro Loma – Poso 70 kV increase due to the RAS operation. However, the results are likely erroneous and misleading because they include time periods in which the Firebaugh switch is inappropriately modeled as closed.

Additionally, the CAISO cannot rely on its results in Table G.10-15 to support its conclusion by only observing the results in April and May--a time during which it modeled the Firebaugh switch as open. The results are not presented at the appropriate level of granularity to draw a negative conclusion during times when the disconnect switch was modeled as open. Table G.10-15 shows that the occurrences of congestion in April and May increase by a total of one occurrence in Alternative 2 compared to the base case. However, the Firebaugh disconnect switch is modeled as open from *mid-month* April to *mid-month* May. It is highly likely that additional congestion was incurred in the periods of time when the switch was inappropriately closed (beginning of April and the end of May). The table only reports the sum of occurrences over the *full month* of April and the *full month* of May which include the time periods when the switch was inappropriately closed.

If the base case is corrected with the Firebaugh disconnect switch open, MCE expects minimal impact on the Oro Loma – Poso 70 kV congestion and should provide significant improvement on the Le Grand – Chowchilla 115 kV congestion shown in Table G.10-14 as well as the full 115 kV path from Newhall to Le Grand.

A RAS that trips local solar generation under the contingency condition is an alternative that is feasible, and MCE requests this alternative be considered by the CAISO as part of the Economic Planning Assessment.

C. Each alternative provides positive net benefits relative to the corrected base case.

Notably, CAISO ran a case in which the Firebaugh switch position is correctly modeled as open from April through October (Alternative 1). Once the net benefit results for Alternatives 3 through 5 are correctly compared to Alternative 1 (as the true base case), each option provides positive net benefits. At a high level, the results provided in the table below indicate that the CAISO, at a minimum, should re-evaluate the net benefits relative to the corrected base case.

	Base case	Panoche/OroLoma A3- reconductoring the 115 kV system		Panoche/OroLoma A4- A1 plus A3		Panoche/OroLoma A5 – A1 plus A2 plus A3	
		Post Project (\$M)	Savings (\$M)	Post Project (\$M)	Savings (\$M)	Post Project (\$M)	Savings (\$M)
ISO load payment	9,823	9,837	-14	9,807	16	9,812	11

ISO generator net revenue benefiting ratepayers	5,755	5,765	10	5,754	-1	5,757	2
ISO transmission revenue benefiting ratepayers	438	445	7	425	-13	426	-12
ISO Net payment	3,630	3,627	3	3,628	2	3,629	1
WECC Production cost	13,938	13,936	2	13,935	3	13,937	1

D. The published reconductoring cost appears to be higher than suggested by PG&E’s Unit Cost Guide

The CAISO estimates the cost of reconductoring the 115 kV lines in the Panoche/Oro Loma area at \$173,000,000. The reconductoring project would include the 115 kV lines between the Oro Loma and Wilson 115 kV buses and between the Newhall and Le Grand 115 kV buses. However, there is insufficient detail to understand and verify these estimates and conclusions.

These upgrades would require approximately 85 circuit miles of reconductoring activity on existing wooden poles through the flat, rural, and agricultural central valley of California. There should be no cost adders for hilly, forested, or mountainous terrain. Likewise, there should be no cost adders for urban/suburban population density. Based on PG&E’s 2022 Unit Cost Guide, such a project would cost \$960,000 per mile, or approximately \$82,000,000. Even if the existing wooden poles are upgraded to lattice towers, the project would cost \$1,519,000 per mile, or approximately \$129,000,000. The discrepancy between these estimates based on publicly available information and the figure CAISO published warrants further elaboration from CAISO on its reported \$173,000,000 project cost. Given a positive net benefit for the reconductoring project with the corrected base case, this project’s cost estimate is a more important factor that requires more details on the cost calculations.

E. The CAISO should provide the cost estimate for the RAS implementation.

As discussed previously, the RAS is a feasible solution for this CAISO area provided the capital cost estimate for the RAS implementation will enable a more comprehensive and complete assessment of the benefits, feasibility, and implementation costs of the opportunities described in the Economic Plan Assessment.

Further, given the Federal Energy Regulatory Commission’s (FERC) April 20, 2023 Ruling in ER22-2362-000 addressing CAISO’s ambient-adjusted line rating tariff definition to improve transparency and accuracy of line ratings pursuant to FERC Order 881 & 881-A, MCE requests the CAISO indicate whether and when it plans to re-evaluate the Panoche/Oro Loma area in light of this Ruling and the CAISO’s movement towards dynamic line ratings by Summer 2025.

[1] Outage ID 11656801

[\[2\]](#) Outage ID 13305482

6. Provide your organization's comments on chapter 5 Interregional Transmission Coordination.

MCE provides no comments in response to this prompt at this time.

7. Provide your organization's comments on chapter 6 Other Studies and Results.

MCE provides no comments in response to this prompt at this time.

8. Provide your organization's comments on chapter 7 Special Reliability Studies and Results.

MCE provides no comments in response to this prompt at this time.

9. Provide your organization's comments on chapter 8 Transmission Project List.

MCE provides no comments in response to this prompt at this time.

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

Order Instituting Rulemaking to Consider
New Approaches to Disconnections and
Reconnections to Improve Energy Access
and Contain Costs.

Rulemaking 18-07-005

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON
ADMINISTRATIVE LAW JUDGE'S RULING ON NEXT STEPS FOR THE
ARREARAGE MANAGEMENT PLAN PROGRAM**

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April 26, 2023

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SUMMARY OF RECOMMENDATIONS

- Continue considering Arrearage Management Plan (AMP) program issues in this rulemaking rather than opening a new rulemaking, given the AMP program is one tool among many being considered in this rulemaking to prevent disconnections;
 - Extend the AMP program for another four years beyond June 11, 2024, but do not connect the extension to the Community Based Organization Pilot (CBO Pilot) given AMP covers a far wider range of customers than the CBO Pilot; and
 - Order an evaluation for the AMP program similar to the Percentage of Income Payment Program evaluation process, to begin immediately, to methodically assess the effectiveness of the AMP program.
-

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**CALIFORNIA COMMUNITY CHOICE ASSOCIATION’S COMMENTS ON
ADMINISTRATIVE LAW JUDGE’S RULING ON NEXT STEPS FOR THE
ARREARAGE MANAGEMENT PLAN PROGRAM**

The California Community Choice Association¹ (CalCCA) submits these Comments in response to the *Administrative Law Judge’s Ruling on Next Steps for the Arrearage Management Plan Program*² (Ruling), dated April 10, 2023.

I. INTRODUCTION

When the California Public Utilities Commission (Commission) opened this Disconnections proceeding in July 2018,³ and ordered the four-year Arrearage Management Plan (AMP) program in June 2020,⁴ it could not have foreseen the impact of the upcoming and lengthy COVID pandemic, and the financial distress that resulted for many Californians. Despite the pandemic, the focus of the proceeding remains the same – to address rising disconnection rates recognizing the critical impact of “energy access . . . to economic and social stability and well-being.”⁵ As energy costs continue to rise, customers struggle to stay current on their energy bills, while disconnections for non-payment

¹ California Community Choice Association represents the interests of 24 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, Energy For Palmdale’s Independent Choice, Lancaster Choice Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy: <https://cal-cca.org/>.

² *Administrative Law Judge’s Ruling on Next Steps for The Arrearage Management Plan Program*, Rulemaking (R.) 18-07-005 (Apr. 10, 2023).

³ See *Order Instituting Rulemaking*, R.18-07-005 (July 12, 2018), at 1.

⁴ See D.20-06-003, *Phase I Decision Adopting Rules and Policy Changes to Reduce Residential Customer Disconnections for the Larger California-Jurisdictional Energy Utilities*, R.18-07-005 (June 11, 2020) (AMP Decision).

⁵ *Id.* at 4.

resume after the pandemic moratorium.⁶ Customers are only now beginning to benefit from the suspension of disconnections while actively enrolled in AMP.

CalCCA has continuously supported the AMP program, while suggesting modifications to the program to increase customer success.⁷ CalCCA also understands from the comments and data provided by the investor-owned utilities (IOUs) that consistent evaluation of the effectiveness of the overall AMP program has been difficult given the COVID pandemic, the disconnections moratorium, the COVID long term payment plans, and the substantial assistance provided by the California Arrearage Payment Program.⁸ As Californians deal with post-pandemic financial struggles, however, CalCCA appreciates the Administrative Law Judge's (ALJ's) focus on "next steps" for the AMP program.

In response to the questions in the Ruling, CalCCA recommends:

- Continuing to consider AMP program issues in this rulemaking rather than opening a new rulemaking, given the AMP program is one tool among many being considered in this rulemaking to prevent disconnections;
- Extending the AMP program for another four years beyond June 11, 2024, but not connecting the extension to the Community Based Organization Pilot (CBO Pilot) given AMP covers a far wider range of customers than the CBO Pilot; and
- Ordering an evaluation for the AMP program similar to the Percentage of Income Payment Program (PIPP)⁹ evaluation process, to begin immediately, to methodically assess the effectiveness of the AMP program.

⁶ See, e.g., *Pacific Gas and Electric Company's (U 39 M) Monthly Disconnection Data Report*, R.18-07-005 (April 20, 2023), Attachment A at 3 (total PG&E customers in arrears for March 2023 was 1,137,602, with 388,256 more than 121 days in arrears; 16,155 customers experienced disconnections for non-payment in March 2023).

⁷ See *California Community Choice Association's Comments on Administrative Law Judge's Ruling Relating to the Phase 2 Workshop in October 2022*, R.18-07-005 (Dec. 9, 2022); *California Community Choice Association's Reply Comments on Administrative Law Judge's Ruling Relating to the Phase 2 Workshop in October 2022*, R.18-07-005 (Jan. 10, 2023); *California Community Choice Association's Reply Comments on Administrative Law Judge's Ruling Directing Utilities to Provide Data and Requesting Comments on Pilot Questions*, R.18-07-005 (Mar. 13, 2023).

⁸ See *Joint Meet and Confer Report*, R.18-07-005 (Feb. 23, 2023).

⁹ See D.21-10-012, *Decision Authorizing Percentage of Income Payment Plan Pilot Programs*, R.18-07-005 (Oct. 7, 2021) (PIPP Decision).

II. CALCCA'S RESPONSE TO QUESTIONS

1. Should the Commission continue to consider AMP program issues in this rulemaking rather than open a new proceeding to consider AMP program issues?

Yes. Given the AMP program is one tool among several (including the PIPP and the CBO Pilot) being considered in this proceeding to prevent disconnections, it makes sense to consider the overall impact and success of the programs together in one proceeding.

2. Should the Commission extend the AMP program beyond June 11, 2024, and if so, for how long? If the Commission approves a Community Based Organization (CBO) pilot program in this proceeding, should the Commission extend the AMP program for a period that relates to the CBO pilot period?

The Commission should extend the AMP program beyond June 11, 2024. The AMP program should be extended for at least another four years beyond 2024 while an evaluation of the effectiveness of AMP through a process established by the Commission, with stakeholder input, is undertaken. As set forth below, the Commission should ensure that a meaningful study to measure the efficacy of AMP should occur within these four years.

CalCCA does not recommend extending the AMP for a period that relates to the CBO Pilot period. The AMP covers a far wider range of customers than the CBO Pilot and should be evaluated independently.

3. When should the Commission evaluate the effectiveness of the AMP program?

The evaluation of the effectiveness of the AMP should begin now, to provide a baseline for future evaluation.

4. How should the Commission evaluate the effectiveness of the AMP program for reducing disconnections and determine whether to modify, extend, or conclude the AMP program? Should the Commission require an independent evaluation of the program, similar to the evaluation provisions we adopted of the Percentage of Income Payment Plan pilot program? What evaluation criteria should the Commission set for the AMP program?

CalCCA recommends that the Commission establish an evaluation program similar to that established for the PIPP program.¹⁰ A third-party evaluation contractor should be retained as part of the AMP evaluation process. As with PIPP, one IOU should be required to conduct a Request for Proposals to hire the independent evaluator based on direction from Energy Division. Energy Division

¹⁰ See PIPP Decision at 73-75.

should then select and supervise the independent evaluator and approve key deliverables, including scope of work, data and metrics required for the evaluation, and the evaluation report.

Included within the overall scope of work for the evaluation contractor is to define what effectiveness of the program looks like based on the goals of the AMP program, and recommendations for improvements to meet program goals. Stakeholders should be given the opportunity to comment on the scope of work, questions being addressed, data and metrics required, and overall evaluation criteria. The evaluator should start with the questions asked by the ALJ of the IOUs in the November 10, 2022 Ruling Relating to the Phase 2 Workshop in October 2022,¹¹ and the follow-up questions in the February 13, 2023 ALJ Ruling,¹² all providing data on customers enrolled in AMP versus other programs. Overall, the evaluator should study not only the reduction in arrearages and overall disconnections, but whether the AMP resulted in behavior change by customers previously in an arrearage “cycle.” Demographic information on who is accessing and benefitting from AMP will also be useful in the overall evaluation. In addition, the evaluator should focus on how IOU and/or community choice aggregator (CCA) marketing, outreach and education (ME&O) impacts customers, including initially enrolling in the program and a customer’s ability to remain successful in AMP. Finally, the evaluator should study how different ME&O and customer service techniques by the IOU and/or CCAs result in different enrollment and success rates.

The costs of the third-party independent evaluator, as well as administrative costs incurred by the IOUs and the CCAs, should be recoverable through the AMP program.

III. CONCLUSION

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

Respectfully submitted,



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

April 26, 2023

¹¹ *Administrative Law Judge’s Ruling Relating to the Phase 2 Workshop in October 2022*, R.18-07-005 (Nov. 10, 2022).

¹² *Administrative Law Judge’s Ruling Directing Utilities to Provide Data and Requesting Comments on Pilot Questions*, R.18-07-005 (Feb. 13, 2023).

I. Answer

A. Marin’s hypotheticals are improbable and irrelevant to whether the CAISO’s proposed tariff revisions are just and reasonable.

When the CAISO faces excessively high demand, the MSOC requirement constrains real-time market awards in peak hours to resource adequacy storage resources to ensure they have sufficient charge to meet their discharge awards from the day-ahead market.³ Marin does not oppose extending this temporary measure and instead focuses its comments on exceptional dispatches and storage generally. Marin notes that “[c]harging during the hours leading up to critical hours may be expensive and inefficient,” and as such, “[f]urther detail regarding the timing of CAISO’s exceptional dispatch instructions and their impacts on energy storage resources’ compensation throughout the operating day would be helpful.”⁴ Marin poses a hypothetical where the CAISO exceptionally dispatches a storage resource “early in the day to completely discharge the resource by hour ending 1400,” potentially forcing the resource to then charge at higher prices to be fully charged for the evening’s net demand peak.⁵

As a preliminary matter, the CAISO notes it has discussed these details at length with stakeholders, and included its exceptional dispatch data on storage resources in the 2022 Summer Market Performance Report, which the CAISO quoted and cited throughout its transmittal letter in this proceeding.⁶ The 2022 Summer Market

³ *California Independent System Operator Corp.*, 175 FERC ¶ 61,168 at P 31 (2021).

⁴ Marin Comments at pp. 5-6.

⁵ *Id.*

⁶ CAISO 2022 Summer Market Performance Report (“Report”)

Performance Report has detailed discussions on storage resources' market behaviors and the very few instances in which the CAISO issued exceptional dispatches to storage resources (despite the extreme conditions the CAISO faced).⁷ As the Report describes, the CAISO only issued exceptional dispatches to storage resources on three days in September 2022 and only between hours ending 13 to 17. None of these exceptional dispatches were to discharge; they were all to charge or hold state of charge to ensure resources were fully charged for the afternoon net peak demand, which generally occurs around hour ending 18.⁸ The CAISO explained that real-time prices caused storage resources to receive discharge schedules that were higher than the expected day-ahead market outcomes, causing state of charge to be lower than expected.⁹

The CAISO agrees that, without the CAISO's energy storage enhancements, storage resources could lose revenues if they received the exceptional dispatches described in Marin's hypotheticals; however the CAISO believes Marin's hypotheticals are extremely unlikely. The CAISO is unaware of any instance when this has occurred. The CAISO's only (and few) exceptional dispatches to date were to charge or hold state of charge in the late afternoon, not *completely discharge* in the early afternoon and then be forced to charge again. The CAISO has not seen market or grid conditions that would necessitate such an unlikely result, nor does Marin identify any such conditions.

<http://www.caiso.com/Documents/SummerMarketPerformanceReportforSeptember2022.pdf>.

⁷ See Report at pp. 146-154.

⁸ *Id.* at 150.

⁹ *Id.*

The CAISO believes such a result is unlikely, especially given CAISO plans to implement new state of charge tools this year.

In any case, this issue is immaterial to whether the CAISO's proposed tariff revisions are just and reasonable and not unduly discriminatory. As the CAISO described at length in its transmittal letter, the MSOC requirement *reduces* the need to issue exceptional dispatches to storage resources. Rejecting the CAISO's filing based on Marin's comments would exacerbate, rather than relieve, the issues of concern to Marin. Moreover, exceptional dispatches are only available when the CAISO must issue them "during a System Emergency, or to prevent an imminent System Emergency or a situation that threatens System Reliability and cannot be addressed by the RTM optimization and system modeling."¹⁰

B. The CAISO has submitted tariff revisions to address any lost opportunity costs for storage resources that receive exceptional dispatches.

Marin also uses this proceeding to "ask[] if the CAISO can provide detail as to whether and how to account for high storage recharging costs subsequent to early day directives to discharge electricity compared to exceptional dispatch compensation for such discharge."¹¹ Marin raises similar questions "as to the accounting of lost opportunity costs for maintaining charge."¹² At the same time, Marin notes that it "plans to submit similar Comments in FERC Docket No. ER23-1533-000 regarding amendments to CAISO's Tariff to implement energy storage enhancements."¹³

¹⁰ CAISO Tariff Section 34.11.1.

¹¹ Marin Comments at p. 6.

¹² *Id.*

¹³ *Id.* at p. 5 n. 9.

The CAISO has addressed compensation for storage resources that receive exceptional dispatches to hold state of charge in the other Commission docket Marin mentions. Stakeholders supported the CAISO's proposed enhancements to ensure storage resources with opportunity costs when they receive an exceptional dispatch to hold a state of charge, and all parties that commented on the issue in the Commission proceeding supported the CAISO's enhancements. Additionally, the Commission approved the MSOC requirement as just and reasonable even before the CAISO proposed to implement the latter enhancements, and the MSOC requirement *decreases* the need to issue exceptionally dispatch storage resources while the CAISO develops replacement enhancements to do the same. As such, Marin's comments do not raise meaningful questions about whether the CAISO's proposed tariff amendments are just and reasonable, and the Commission should thus approve the temporary extension of the MSOC requirement for the reasons explained in the CAISO's transmittal letter.

II. Conclusion

For the reasons explained above and in this proceeding, the CAISO respectfully requests that the Commission accept the proposed tariff revisions as filed.

Respectfully submitted,

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Dated: April 28, 2023

CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing document upon all of the parties listed on the official service list for the above-referenced proceeding, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010).

Dated at Folsom, CA this 28th day of April, 2023.

/s/ Jacqueline Meredith

Jacqueline Meredith