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STATE OF CALIFORNIA
CALIFORNIA ENERGY COMMISSION

In the Matter of: The 2023 Integrated Energy Policy Report	Docket No.: 23-IEPR-01

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE DRAFT 2023 INTEGRATED ENERGY POLICY REPORT

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STATE OF CALIFORNIA
CALIFORNIA ENERGY COMMISSION

In the Matter of: The 2023 Integrated Energy Policy Report	Docket No.: 23-IEPR-01

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE DRAFT 2023 INTEGRATED ENERGY POLICY REPORT

The California Community Choice Association[1] (CalCCA) submits these comments to the California Energy Commission (Commission) on the *Draft 2023 Integrated Energy Policy Report*, dated November 13, 2023 (Draft IEPR).

I. INTRODUCTION

The Draft IEPR correctly notes the "tradeoffs" that must be balanced across multiple objectives to achieve rapid electrification, electric supply decarbonization, reliable electric service, hardening the grid and adapting to increased wildfires from climate change, affordability, and equity.[2] The Draft IEPR identifies barriers to meeting these objectives in the context of

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1 California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Ava Community Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, Energy For Palmdale's Independent Choice, Lancaster 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 *See* Draft IEPR, at 18-19 ("Electricity infrastructure must provide reliable service and be resilient to California's increasingly variable climate. Planners, regulators, and utilities must simultaneously balance investments in grid hardening and wildfire adaptation with expanding capacity to accommodate rapid growth in clean energy resources. At the same time, electricity must remain affordable, and the costs, benefits, and access to clean energy resources need to be more equitable. . . The critical challenge facing planners, regulators, systems operators, and utilities today is balancing tradeoffs between these objectives.").

connecting clean energy resources to the electricity grid, and recommends solutions to address the challenges related to the procurement needs, including: (1) adapting existing planning paradigms (including demand forecasting and electric grid planning) to accommodate the accelerated deployment of new resources; (2) efforts to better manage interconnection of new clean resources; (3) limiting burdens on ratepayers resulting from the deployment of new resources, and upgrading and hardening the grid; (4) increasing transparency of available transmission and distribution capacity for customers or project developers to connect to the grid; and (5) expanding public engagement and awareness campaigns to expedite permitting processes.[3] While all of these barriers are indeed relevant to the discussion related to challenges California is facing during the clean energy transition, the following additional items must also be incorporated into the IEPR to ensure a full picture is presented:

- The Commission should incorporate a discussion of Resource Adequacy (RA) market scarcity and high RA prices into the discussion of potential reliability and cost-effectiveness challenges;
- The Commission should emphasize the magnitude of the shift in clean energy policy goals over a short period of time and the implications for achieving accelerated deployment; and
- The Commission should provide more detail on approaches to limit the ratepayer burden for paying for climate initiatives.

[3] *See id.,* at 13-56 (Chapter 1 discussing speeding deployment and connection of clean resources to the grid).

II. THE COMMISSION SHOULD INCORPORATE RESOURCE ADEQUACY ISSUES INTO THE IEPR ANALYSIS OF INTERRELATED GRID AND RELIABILITY CHALLENGES

A. Challenges Resulting from Resource Adequacy Market Scarcity and High Prices Should Be Incorporated into the IEPR Reliability Analysis Along with Procurement Challenges

As discussed in CalCCA's Comments on the Scoping Order in this Docket (Scoping Order Comments),[4] the IEPR should not only address California's energy procurement challenges, but should also evaluate the reliability impacts of load-serving entities (LSEs) being challenged to meet their RA compliance obligations. As noted in the Scoping Order Comments, the California Public Utilities Commission (CPUC) is currently changing the methodology to compute minimum RA requirements by requiring LSEs to provide capacity for an entire month in all available hours.[5] While the peak need for RA is not greater than the IEPR's identified energy need, the RA will be required for all hours rather than just the peak hours.[6] Therefore resource owners will face a significantly greater obligation to meet an RA purchaser's needs than they would to sell energy at a single peak hour of the year.[7] As a result, meeting RA obligations is becoming increasingly difficult. Failure to procure sufficient resources to meet RA requirements results in LSEs facing substantial penalties through the CPUC program, ranging from $4.44/kilowatt (kW) month in the winter to as high as $26.64/kW-month in the summer.[8] A deficient entity can also face backstop costs from the California Independent System Operator (CAISO).[9]

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4 *See* Docket No. 23-IEPR-01, *California Community Choice Association's Comments on the Scoping Order for the 2023 Integrated Energy Policy Report* (Sept. 18, 2023), at 3: https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=23-IEPR-01.

5 Scoping Order Comments, at 3-4.

6 *Ibid.*

7 *Ibid.*

8 *Ibid.*

9 *Ibid.*

In addition to the increased obligations, the current RA market is extremely tight, as explained in the Scoping Order Comments and the CalCCA whitepaper on RA scarcity, entitled "California's Constrained Resource Adequacy Market: Ratepayers Left Standing in a Game of Musical Chairs."[10] CalCCA's whitepaper demonstrates that the available supply of RA exceeded the demand in September 2023 by a razor-thin margin of 540 megawatts (MW). This scarcity of supply results in the difficulty, if not the impossibility, of every LSE meeting its RA requirements. CalCCA estimates that the tight RA market conditions are likely to persist through 2026.[11] This RA supply deficiency prevents collective compliance by CAISO LSEs despite best efforts to procure and willingness to pay exorbitant prices.

As a result of the RA scarcity, serving California electricity customers has become more expensive. CalCCA's analysis demonstrates that the weighted average price for RA increased between September 2019 and September 2021 by over 100 percent from $4.08/kW-month to $8.62/kW-month.[12] CalCCA analysis of public capacity transaction data in the Federal Energy Regulatory Commission's (FERC's) Electronic Quarterly Reports (EQR) also shows that the weighted-average price for capacity delivered to the CAISO system continued to rise, exceeding $13/kW-month in 2023.[13] As noted in CalCCA's whitepaper, the lack of sufficient capacity available to meet RA needs is clearly driving up costs for California electricity customers. Since RA is the methodology to assure grid reliability, the IEPR should address the efficacy of the RA market and mechanism to ensure that California's electricity customers are provided with a reliable grid at affordable cost.

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10 The Scoping Order Comments discussed and attached the CalCCA RA Whitepaper dated September 15, 2023. CalCCA continually updates the data cited in the Whitepaper – attached hereto is the most recent version (dated December 1, 2023) of the Whitepaper.

11 CalCCA RA Whitepaper (Dec. 1, 2023), at 6.

12 Scoping Order Comments, at 7-8.

13 CalCCA RA Whitepaper (Dec. 1, 2023), at 9-10.

B. IEPR Recommendations to Speed Deployment and Connection of Clean Resources Should Address Resource Adequacy Challenges and Include Potential Regulatory Solutions

RA scarcity and high RA prices raise significant reliability and cost-effectiveness concerns, and should be included among the "problems" identified in the IEPR that must be solved to meet California's energy goals. As noted in the Draft IEPR, market, legislative and regulatory process solutions should be considered to overcome the identified barriers.[14] While bringing new resources online over time will contribute to overcoming the RA scarcity challenge, CalCCA continues to encourage the CPUC to allow waivers for the system and flexible RA penalties upon a showing of good faith efforts by an LSE to procure the required RA. Such waivers could be considered on a case-by-case basis, with the burden of proof on the LSE to prove the efforts made to acquire the capacity. Given the shortages and difficulties LSEs are encountering in the market, such as developers missing deadlines from interconnection or supply chain issues, the LSEs should not be penalized when the reason for missing a RA requirement deadline is no fault of their own. If a waiver is granted, customers will benefit as the costs of the penalties will not trickle down to rates. Such a regulatory process change will not impact reliability, as LSEs will still be required to meet all RA obligations. However, the regulatory agencies can improve cost-effectiveness and affordability for ratepayers by allowing waivers in very limited circumstances. The IEPR should include the RA scarcity issue in its list of challenges, and provide potential recommendations and solutions to mitigate the impacts on ratepayers.

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[14] *See* Draft 2023 IEPR, at 29 ("[t]he state's infrastructure planning and regulatory processes must now adapt to rapid load growth enabling beneficial electrification coupled with decarbonization of electricity supply. Keeping pace with market- and policy-driven clean resource deployment will require development of more proactive and flexible processes.").

III. THE COMMISSION SHOULD EMPHASIZE THE MAGNITUDE OF THE SHIFT IN CLEAN ENERGY POLICY GOALS OVER A SHORT PERIOD AND THE IMPLICATIONS FOR ACHIEVING ACCELERATED DEPLOYMENT

CalCCA supports the Commission's identification of accelerated deployment straining the existing planning paradigms as a major barrier.[15] The Commission should also emphasize the role of rapidly changing policy goals in contributing to this strain. The CAISO 2021-2022 Transmission Plan[16] finds that the shift from Renewables Portfolio Standard (RPS) -related policies to aggressive 2030 greenhouse gas reduction goals set out by the California Air Resources Board (CARB), CPUC, and CEC in response to Senate Bill (SB) 100 requires significant investment in new transmission infrastructure.[17] Over four cycles of the transmission planning process, the planned rate of renewable deployment went from about 1 gigawatt (GW) /yr. in the 2019-2020 Transmission Plan, which focused on meeting 60 percent RPS goals,[18] to about 7 GWs/yr. in the 2022-2023 Transmission Plan, which focused on meeting SB 100 goals.[19] Over those same four planning cycles, the planned investment in new transmission increased from $0.14 billion[20] to $7.3 billion.[21] The increase in new transmission investment is even more significant when one considers that the 52 fold increase in transmission cost is not the complete set of transmission assets necessary to meet the SB 100 goals. The total cost of new transmission build will only be known as further transmission planning identifies and approves the necessary assets. The CAISO expects that the 45 transmission projects identified in the 2022-2023 plan

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15 *See* Draft IEPR, at 28-29.

16 CAISO 2021-2022 Transmission Plan. https://www.caiso.com/InitiativeDocuments/ISOBoardApproved-2021-2022TransmissionPlan.pdf.

17 *Id.*, at 15.

18 *See* CAISO 2019-2020 Transmission Plan. https://www.caiso.com/Documents/ISOBoardApproved-2019-2020TransmissionPlan.pdf, at 6.

19 *See* CAISO 2022-2023 Transmission Plan. https://www.caiso.com/InitiativeDocuments/ISO-Board-Approved-2022-2023-Transmission-Plan.pdf, at 16.

20 *See* CAISO 2019-2020 Transmission Plan, at 11.

21 *See* CAISO 2022-2023 Transmission Plan, at 3.

will be phased in with a lead time of eight to ten years.[22] Hence, the accelerated deployment is in response to changing policy goals and will take time and significant investment to build the necessary infrastructure.

IV. THE COMMISSION SHOULD PROVIDE MORE DETAIL ON APPROACHES TO LIMIT THE RATEPAYER BURDEN FOR PAYING FOR CLIMATE INITIATIVES

CalCCA supports the Commission's recommendation to evaluate alternative sources for funding transmission and distribution system upgrades.[23] Initiatives to increase electrification to mitigate climate impacts will likely stall if ratepayers are burdened with all the up-front costs of transforming the grid. CalCCA suggests that the Commission provide more detail on how it will identify and evaluate strategies for reducing reliance on ratepayers to fund climate initiatives.

V. CONCLUSION

CalCCA looks forward to further collaboration on this topic.

Respectfully submitted,

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December 1, 2023

22 *Id.,* at 4.

23 *See* Draft IEPR, at 46.

ATTACHMENT
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE DRAFT 2023 INTEGRATED ENERGY POLICY REPORT

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

(Updated December 1, 2023)

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

Updated December 1, 2023

1. Introduction

The Resource Adequacy (RA) supply available within the California Independent System Operator (CAISO) balancing area for 2023 appears to have been inadequate to meet the RA program compliance requirements, depending on the availability of RA imports. The "stack" analysis in Figure 1 below, which compares RA requirements with the available RA supply, demonstrates that the margin was razor thin "on paper."[1] The 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, 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 California[2] 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 percent, with a 20-22.5 percent "effective" PRM for investor-owned utilities (IOUs), increased RA requirements.

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[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 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 resources 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 showings for 2024 show 4,900 MW of RA imports, indicating a recovery from the 2022 lows, but still substantially below 2020 levels. The CAISO has not yet published updated information for year-ahead RA imports for 2023. Import Capability Used in RA Plan Data downloaded from oasis.caiso.com.

- 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 likely prevented 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 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. Prices for resources averaged $3.63 kilowatt (kW)-month in 2019;[3] summer 2023 has seen individual transactions at prices over $60 kW-month – the highest for CCAs being $82.94/kW-month – and resources are increasingly unavailable at any price. 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

[3] *2019 Resource Adequacy Report*, March 2021: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2019rareport-1.pdf, at 22.

RA imports.[4] RA supply is primarily derived from the CPUC'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, the available supply of RA exceeded demand for RA by a razor-thin margin of 514 megawatts (MW), even after accounting for expected RA imports, in September 2023. Supply was similarly scarce to meet RA demand in August 2023. The scarcity of supply made it difficult, if not impossible, for every LSE to meet its RA requirements.

Figure 1

		Jun	Jul	Aug	Sep
1	CAISO 1-in-2 Load	42,354	45,510	46,074	46,829
2	Reserve Margin (16%)	6,777	7,282	7,372	7,493
3	**Total RA Demand**	**49,131**	**52,792**	**53,446**	**54,322**
4	2023 NQC List	48,669	49,420	49,148	49,526
5	Event-Based Demand Response	995	1,045	1,077	1,090
6	Imports	6,000	6,000	6,000	6,000
7	Thermal Plant Derate	(718)	(718)	(718)	(718)
8	Excess IOU Resources In IOU Supply Plans	(1,266)	(507)	(396)	(443)
9	Retention for Substitution	(619)	(619)	(619)	(619)
10	**Total RA Supply**	**53,060**	**54,621**	**54,491**	**54,836**
11	Surplus Supply (Deficit)	3,929	1,829	1,045	514

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 8 and 9, 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 CEC's 2022 Integrated Energy Policy Report Planning scenario.[5]
2	Planning Reserve Margin per CPUC D.22-06-050.[6]

4 The data for Figure 1 are current as of December 1, 2023. The CAISO has not yet published updated information for imports for 2023, and therefore the import amounts have been estimated based on historical imports. *See infra at* 4, Table row 6.

5 Monthly maximum managed net load forecast for 2023 from the California Energy Demand 2022 Hourly Forecast for CAISO in the Planning Scenario: https://efiling.energy.ca.gov/GetDocument.aspx?tn=248359&DocumentContentId=82768.

6 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.

Row(s)	Source
4	CPUC 2023 NQC List. The CPUC lists the net qualifying capacity (NQC) for all resources in the CAISO footprint for 2023.[7] CalCCA exclude from the list all resources with a commercial online date later than one month before the applicable RA month. CalCCA found the commercial online date by matching the resource identification number (resource ID) in the NQC list to the resource ID in the CAISO Master Generating List.[8]
5	Event-Based Demand Response. Demand response quantities are from the CPUC's Resource Adequacy Compliance Materials.[9] Demand response totals include avoided losses and are from event-based programs at PG&E, SCE, and SDG&E.
6	Imports. Imports reflect the CEC's assumed RA imports available to the CAISO market.[10] These imports exceed the year-ahead showing of RA imports by 2,400 MW compared to the 2022 showing and 1,100 MW compared to the 2024 showing.
7	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.[11] CalCCA's approach parallels recent CPUC discussions regarding the need to include thermal derates in reliability modeling.[12]
8	D.21-12-015 allowed: "excess resources from an IOU's *existing* portfolios may be used to meet or supplement these procurement targets up to the upper end of its contingency procurement target."[13] D.21-12-015 also 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

7 2023 NQC List for CPUC Compliance (October 17, 2023 version): https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/cpuc-final-net-qualifying-capacity-report-for-compliance-year-2023-17oct23.xlsx

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

9 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.

10 Joint Reliability Planning Assessment - SB 846 Second Quarterly Report, at Table 4: https://efiling.energy.ca.gov/GetDocument.aspx?tn=250176&DocumentContentId=84899. The CEC's assumed imports increased from 5,500 MW in the February 2023 assessment to the May 2023 assessment based on agency staff assessments of market conditions.

11 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.

12 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.

13 D.21-12-015, Phase 2 Decision Directing Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company to Take Actions to Prepare for Potential Extreme Weather in the Summers of 2022 and 2023, R.20-11-003 (Dec. 2, 2021), at 103: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M428/K821/428821475.PDF. .

14 *Id.* at 101-102.

Row(s)	Source
	intended to be incremental to supply available to LSEs to meet their 16 percent 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. Line 8 represents the subset of the resources shown on the three IOUs' supply plan as filed in the IOU 2023 Excess Resources Report.[16]
9	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]

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 planning reserve margins for 2024-2026 increase to 17 percent;[19]
- 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;[20]

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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 Excess Resources Reports from https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-compliance-materials.

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

18 D.22-06-050 at 128.

19 *Id.* at 125 (requiring a 17 percent PRM for 2024, we assume the same for 2025-26).

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

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- Excess IOU procurement for a higher effective PRM continues through 2025;[21] and
- For the years 2024 through 2026, the NQC List is based on the 2024 NQC list, though limited to resources built by the beginning of 2023.[22] Expected contracts for new-build resources are added to the list of resources. September new resources build is based on resources online by the end of Q2 in each year.[23]

Figure 2

	September NQC	2023	2024	2025	2026
1	CAISO 1-in-2 Load	46,829	47,475	47,987	48,487
2	Reserve Margin (16% in '23, 17% after)	7,493	8,071	8,158	8,243
3	**Total RA Demand**	**54,322**	**55,546**	**56,145**	**56,730**
4	NQC List	49,526	46,227	46,227	46,227
5	Event-Based Demand Response	1,090	980	955	978
6	Imports	6,000	6,000	6,000	6,000
7	Estimate of Contracted Resources	-	7,366	9,806	10,126
8	Thermal Derates from 2023 NQC List	(718)	(723)	(723)	(723)
9	Remove Diablo from Planning	-	-	(2,280)	(2,280)
10	OTC, Retired or Contracted by DWR	-	(2,859)	(2,859)	(2,859)
11	Excess IOU Procurement for Higher Effective PRM	(443)	(1,700)	(1,700)	-
12	Retention for Substitution	(619)	(619)	(619)	(619)
13	**Total RA Supply**	**54,836**	**54,672**	**54,807**	**56,850**
14	Surplus Supply (Deficit) [Assuming Loss of Diablo]	514	(874)	(1,338)	120

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 percent. 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 lower completion of new resources for September 2023 than actually observed (1,750 MW vs. 1,905 MW);

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[21] Excess procurement of 1,700 MW for 2024 and 2025 is pursuant to a proposed decision in R.21-10-002, representing the minimum targeted procurement defined by the CPUC. IOUs would be authorized to procure as much as 3,200 MW for those same years, potentially increasing the deficits shown in Figure 2.

[22] 2024 NQC List for CPUC Compliance (November 16, 2023 version): https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/cpuc-finalnetqualifyingcapacityreportforcomplianceyear2024-16nov23.xlsx

[23] Expected contracted resources from the Joint Reliability Planning Assessment - SB 846 Third Quarterly Report, Table 2: https://efiling.energy.ca.gov/GetDocument.aspx?tn=251991

- 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 2,323 MW of wind and solar NQC in the RA stack;
- Uses earlier data for the 2023 NQC list and assumptions for imports (5,500 MW vs. the more recent 6,000 MW assumption);
- 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;
- 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 2023 – 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.[24]

[24] 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.

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. The Impact of Weather on Capacity

The changes in precipitation levels from 2022 to 2023 have been an extreme that helps to demonstrate the impact of weather on capacity. As of June 14, 2023, the California Department of Water Resources (CDWR) reports that the water content of snowpack for the State is at 333 percent of normal.[25] On the same day in 2022, CDWR reported that the snowpack had already melted leaving the state at zero percent of normal. In addition to the snowpack, rain has helped to fill reservoirs prior to the snow melt placing many of California's reservoirs above their historical average as early as March.[26]

Using data from the CEC from the past 20 years, 2006 had the highest amount of energy production from hydroelectric generating facilities at 48,559 gigawatt hours (GWh). This high was reached on installed capacity of 13,557 MW of large and small hydro in California at the time for a capacity factor of 40.9 percent. This compares with 2022 where the CEC shows energy generation of 17,612 GWh from an installed capacity of 14,035 MW for a capacity factor of 14.3 percent.[27] Simply put, more water yields more energy. Since the amount of installed capacity in 2023 from large and small hydro is at least as much as it was in 2006, given the amount of available water, it is reasonable to expect that the energy production in 2023 was similar to that in 2006.

[25] https://cdec.water.ca.gov/snowapp/sweq.action.
[26] https://cdec.water.ca.gov/reportapp/javareports?name=STORSUM.202303.
[27] https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/electric-generation-capacity-and-energy.

The RA program counts capacity from resources based on their capability of providing that level of output in a sufficient number of hours to meet system load needs. The RA program will therefore derate the amount of capacity from hydroelectric facilities to account for water available for use at the facility. In 2022, this amount was at historic lows. In fact, the process for RA had the Year-Ahead showing for 2023 occurring in October 2022. At that point in time, CDWR reported snow-pack levels at zero percent of normal. Without knowing that the 2022-2023 precipitation season would be as good as it turned out, the amount of hydroelectric generation for RA was likely assumed to be at very low levels for the Year-Ahead showing process. These expectations likely had a significant effect on the amount of hydro output offered as RA in the Year-Ahead process.

This issue does not only impact California. Hydroelectric generation is prevalent in the Pacific Northwest and there are significant quantities in the Southwest as well. With uncertainty surrounding the amount of precipitation that either of those areas would receive, entities were unwilling to sell significant amounts of import capacity for the Year-Ahead process.

With conditions better known in June, significant amounts of hydroelectric generation in and out of state were likely available, easing the tight capacity market. High hydro conditions were good news for 2023 for California's Month-Ahead RA process but did nothing to cure the lack of capacity for the already complete Year-Ahead RA process. Importantly, it further has little bearing on what the hydroelectric conditions will bring for 2024 onward.

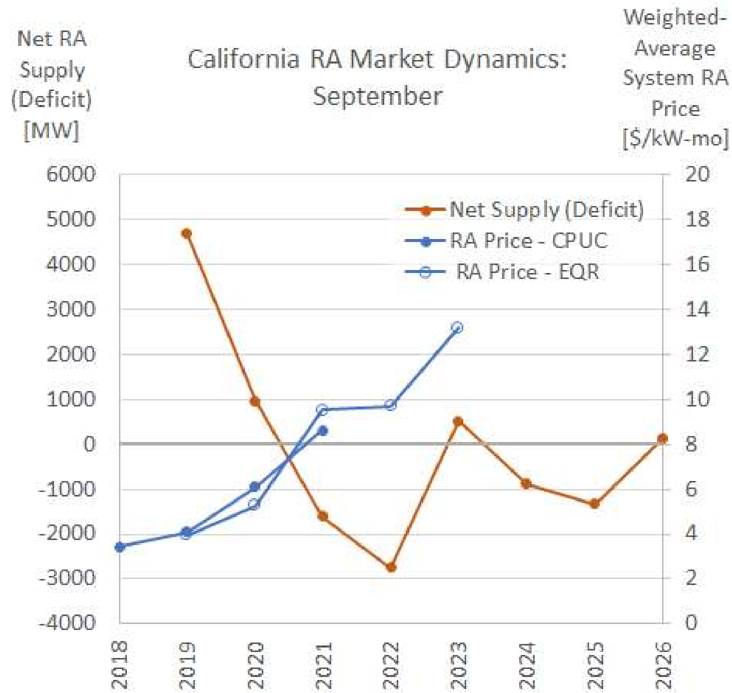
7. The Shortage of RA has Capacity Prices at All Time Highs

As basic economics would predict, these conditions are ripe to produce exorbitant prices, making reliably serving California's electricity customers more expensive. Between September 2019 and September 2021, the net RA supply decreased by 6 GW[28] while the weighted average price for September RA increased by over 100 percent from $4.08/kW-month to $8.62/kW-month (see Figure 4 below).[29] CalCCA analysis of public capacity transaction data in FERC Electronic Quarterly Reports (EQR) shows that the weighted-average price for capacity delivered to the CAISO system continued to rise to over $13/kW-month in 2023.

[28] CalCCA estimated the net RA supply in September for 2019-2022 using assumptions similar to the 2023 RA Stack in Section 3. Key differences include the use of a 15 percent PRM, load forecasts from the CED 2019 and CED 2021, NQC lists from the relevant year, event-based demand response from the relevant year, historical import RA from the relevant year, and no excess IOU procurement for higher effective PRM.

[29] 2021 Resource Adequacy Report (Apr. 2023), at 29: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2021_ra_report_040523.pdf.

Figure 4



Importantly, detailed transaction level data from the FERC EQRs shows that the rise in average capacity prices is primarily driven by a growing share of transactions at extremely high prices (See Figure 5, below). In September 2020, a time with excess RA supply, around 2,800 MW of RA capacity was purchased by California LSE's at prices above \$7.34/kW-mo, the CAISO's recently proposed soft-offer cap for the capacity procurement mechanism (CPM).[30] In contrast, more than 7,800 MW, 10,600 MW, and 11,700 MW were purchased at prices above \$7.34/kW-month in September 2021, 2022, and 2023 respectively, times with an RA deficit or extremely tight market. The highest observed prices rose from \$17/kW-mo in September 2020 to over \$60/kW-mo in September 2021, 2022, and 2023. LSE's faced with a responsibility to meet their RA obligation at any cost are being met with generators only willing to sell at prices five to eight times higher than the CAISO soft-offer cap. The lack of sufficient capacity available to meet RA needs is clearly driving up costs for California electricity customers.

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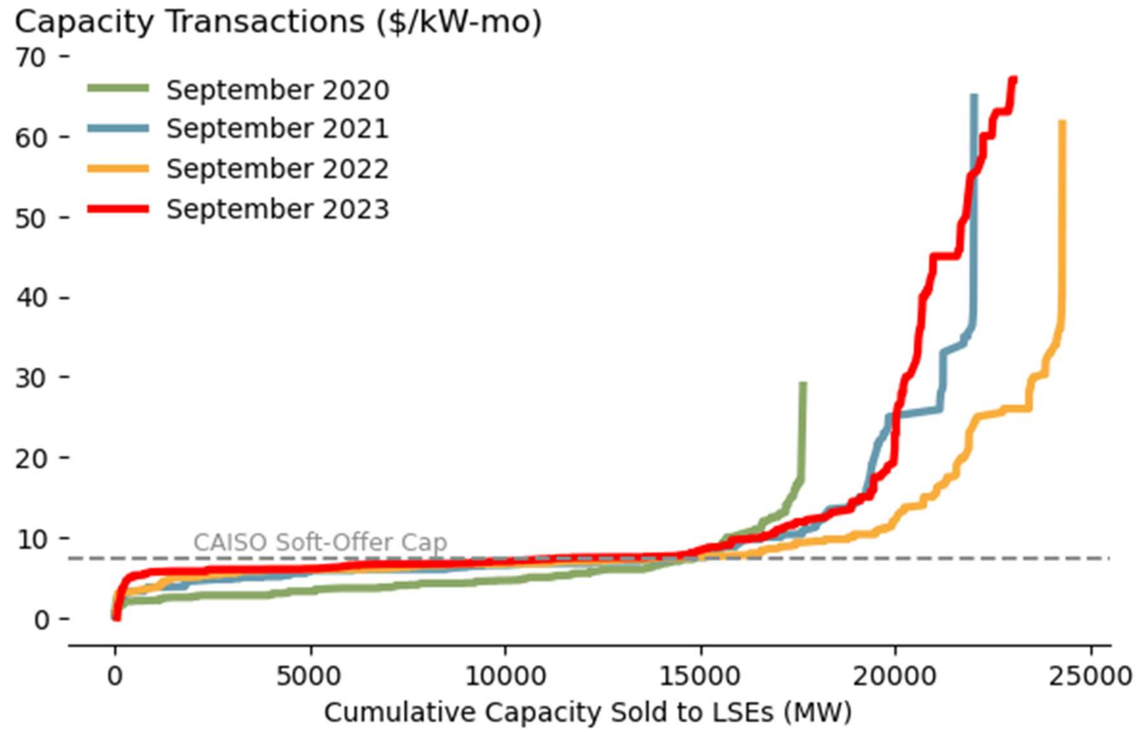
[30] *Capacity Procurement Mechanism Enhancements*, Track 2 Straw Proposal (June 30, 2023): http://www.caiso.com/InitiativeDocuments/StrawProposal-CapacityProcurementMechanismEnhancements-Track2.pdf.

Figure 5



8. Tight Market Conditions Across the West Limit Availability of RA Imports

The ability of California LSEs to meet their RA obligations in 2023 into future years depends on the availability of RA imports from the rest of the West. Across the West, resource adequacy has become a priority issue as regions experience load growth, retire aging coal plants, and turn to resources like solar for future needs. Demonstrating the importance of RA, utilities across the West supported the development of the Western Resource Adequacy Program (WRAP) as a mechanism to formalize resource counting and to share excess resources when needed in the operational timeframe.[31] Currently, however, no entity regularly quantifies the excess supply of RA in the West that is available for California LSEs to rely on for imports.

We use public reliability assessment data, primarily from the North American Electric Reliability Corporation (NERC), to provide visibility into trends in the availability of RA resources outside of California. We consider both historical data and projections to evaluate the potential implications for California RA markets.

The availability of resources to import into California depends on whether other sub-regions of the Western Electricity Coordinating Council (WECC) have generating capacity that exceeds their peak demand and planning reserve margins. NERC summer reliability assessments (released in May of each year) provide prompt year peak load forecasts and on-peak resource

[31] WRAP: https://www.westernpowerpool.org/about/programs/western-resource-adequacy-program

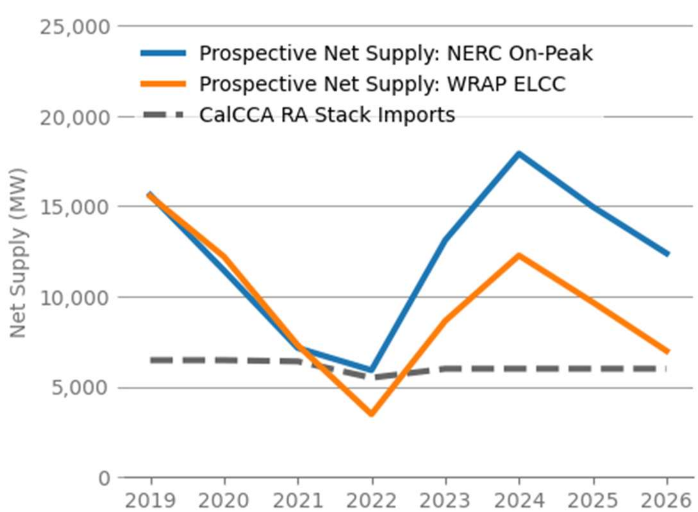
totals for each WECC sub-region. NERC's long-term reliability assessments (released in December each year) provide ten-year projections of loads and resources.

We assume that the resources available to California as RA imports can be calculated as the net supply aggregated across all the non-California WECC sub-regions, where net supply is the amount that the prospective on-peak resource capacity exceeds the peak demand forecast plus a planning reserve needed to meet the Reference Reserve Margin. Due to several limitations in the data and methodology, this net supply calculation is not an exact assessment of available imports, instead it is a proxy whose value over time should reflect trends in the true import availability over the same time horizon. The limitations of this approach include:

- NERC reports non-coincident peaks across WECC sub-regions, meaning that the reported peaks are not expected to be reached at the same time;
- Aggregating resources and demand across all of the WECC sub-region ignores inter-region transmission limits and overstates the availability of supply;
- The approach treats the Reference Reserve Margin as a level of planning reserves that must be met prior to exporting; in reality, California is unique in specifying a mandated planning reserve margin.

Another limitation of the NERC data is that it reports contributions of prospective resources based on their on-peak production. It is apparent in California, that as the share of solar grows, production during the net peak rather than gross peak becomes a more reasonable assessment of the reliability contribution of solar. The WRAP assesses reliability contributions of wind and solar based on effective load carrying capability (ELCC) studies that account for the shifting periods of greatest reliability need. We calculate net supply using the NERC On-peak values and the proposed ELCC values for wind and solar from the WRAP program, based on values applicable to August.

Figure 6



Across the non-CA WECC, the prospective net supply is positive in all years between 2019 and 2026, suggesting RA resources are available to import into California. The size of available resources, however, appears to change dramatically across years, Figure 6. A 15 GW surplus in resources fell to only 4-6 GW by 2022 because of an increase in load between 2019 and 2020 and a decrease in generation capacity from 2020 to 2022, largely associated with coal plant retirements. The RA imports in the CalCCA RA stack closely tracks the prospective net supply in the Non-CA WECC, suggesting that nearly all of the available resources were imported into California.

New resources were added after 2022 and additions are expected to continue through 2024 at a rate that exceeds load growth, reducing the tightness in the non-CA WECC region and again freeing up resources to import into California. The major source of new capacity between 2022 and 2024 is solar with some growth in storage, geothermal, and hydropower.

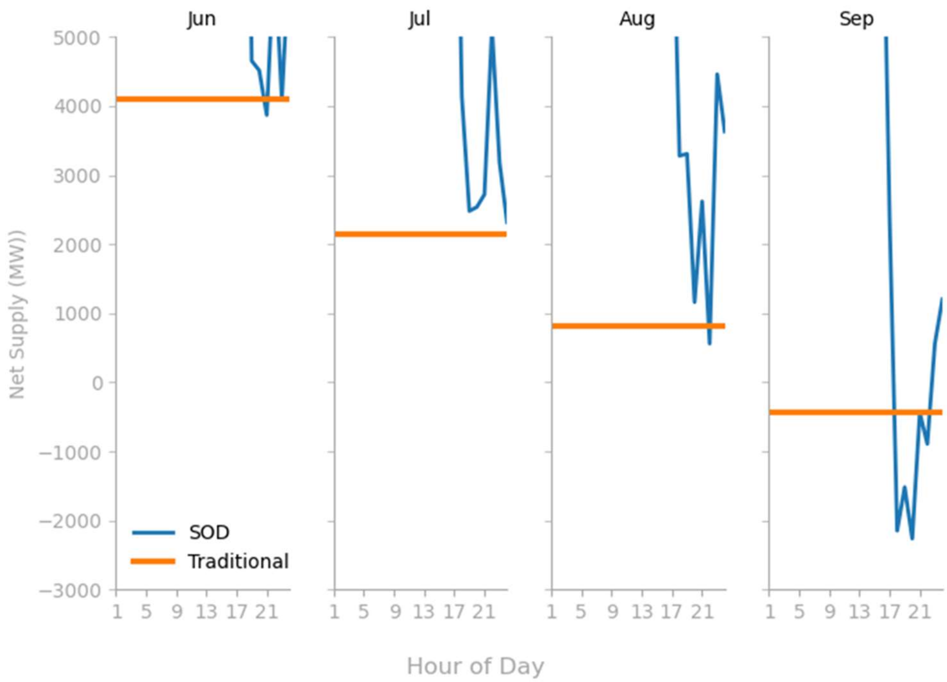
Whether the net supply surplus in the Non-CA WECC region returns to its 2019 levels depends on the capacity accreditation of solar. Using WRAP ELCC values for solar and wind capacity accreditation reduces the net supply surplus by 5.6 GW relative to the surplus calculated with NERC On-Peak values in 2024. The difference in net supply between the two methods continues to be about 5-6 GW through 2032. The lower net supply surplus with the WRAP ELCC values suggests that widespread participation of utilities in the WRAP program may mean that fewer resources are available to import into California.

9. The New CPUC Slice of Day RA Mechanism Will Not Address Thin Supply Margins

In the current Resource Adequacy framework, LSEs procure RA resources for each month of the year to meet their allotted share of the monthly peak demand and planning reserve margin. The contribution of a resource toward the RA obligation is based on its NQC, represented by a single value each month. Beginning in 2025, the Resource Adequacy framework will shift to a new "Slice-of-Day" framework in which the monthly RA obligation is defined for each of the 24 hours in a day and the contribution of a resource can similarly vary by hour of the day. To analyze the implications of this new framework CalCCA developed a "Slice of Day" RA stack analysis for 2023 using data and assumptions similar to the RA stack presented in Section 3. The results show that in critical months, the shift to the Slice-of-Day framework will further tighten the resource adequacy market, Figure 7.

The SOD framework will expose existing constraints currently masked by the annual-peak RA requirements measure. Many hours of the day have significant surplus supply, but not in early evening hours after sunset. In the early evening, the net supply in the SOD stack is at its lowest and, as shown in Figure 7, can be lower than the net supply calculated with the traditional RA stack for the same set of resources. Months in which the SOD net supply is lower than the traditional net supply will lead to a tighter RA market and greater challenges for LSEs to meet their RA obligations. For the resources and demand in the 2023 RA stack, the most challenging month was September in both the SOD and traditional approach, with hour ending 20 the most critical hour in September.

Figure 7



The differences between the Slice of Day stack and the traditional RA stack include:

- Demand: For SOD, demand is represented by the 24-hourly values on the day with the highest peak load of each month.[32] For the traditional stack, demand is the single highest peak load of each month. The 16 percent planning reserve margin is applied to all 24 hours in SOD and the highest load hour in the traditional stack.
- Wind and Solar: For SOD, the contribution of wind and solar varies by hour and is calculated from exceedance values with historical data.[33] For the traditional stack, the contribution of wind and solar is based on a monthly estimate of the effective load carrying capability (ELCC).
- Energy Storage: For SOD, the contribution of storage to any hour is constrained based on characteristics of the resource, including the power rating, the maximum sustained discharge energy, the maximum number of daily cycles, and the availability of excess capacity to charge the storage.[34] Within these capabilities storage is dispatched to

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32 Hourly managed net load forecast for 2023 from the California Energy Demand 2022 Hourly Forecast for CAISO in the Planning Scenario: https://efiling.energy.ca.gov/GetDocument.aspx?tn=248359&DocumentContentId=82768.

33 CPUC Master Resource Database version 3: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/mrd-draft-2.xlsx. The exceedance profiles for wind and solar vary by technology and location.

34 Ibid.

minimize any deficits in net supply, or if none exist, to flatten out the net supply.[35] For the traditional stack, the contribution of storage is based on its full nameplate capacity (or proportionally derated if the maximum discharge duration is less than 4 hours.).

- Imports: For the SOD, imports are assumed to be available between hour ending 7 and hour ending 22 following the common "6 X 16" contract schedule. In the traditional stack RA import estimates are based on estimated availability during early evening hours.

The primary reason why the SOD net supply in hour ending 20 is lower than the traditional net supply in September is differences in the contribution of solar. In the traditional RA stack, solar resources contribute up to 11 percent of their nameplate capacity toward the RA supply. In the SOD stack, on the other hand, the contribution of solar to supply in hour ending 20 is nearly zero based on the calculated exceedance values.

Design elements of the SOD framework may further exacerbate the challenges relative to the analysis presented above. In the above analysis, all sources of supply and all demand are pooled prior to calculation of the hourly net supply. In practice, the SOD framework will require that each LSE meet its 24-hour obligations only with resources in its portfolio. Unless there are changes to the proposed SOD framework, resources cannot be subdivided hourly to optimize the LSEs' portfolios. Depending on the composition of individual LSE portfolios and the 24-hour shape of their demand profile, the net supply from first pooling all loads and resources, as assumed in this stack, may be greater than the aggregate net supply without pooling, reflecting the constraints on individual LSE showings. Two examples illustrate this challenge:

- An LSE with a net surplus in one hour cannot allocate that surplus to another LSE with a deficit in the same hour unless they transfer all 24-hours of capability from the resource to the other LSE.
- The charging energy for storage must be met by surplus supply within an LSE's own portfolio, any excess charging energy in another LSE's portfolio is not transferable without trading all 24 hours of the capability of an excess resource.

Even achieving the net supply shown in this SOD stack may require modifications to the framework such as adding transactability of LSE load obligations or individual hours of a resource. Nevertheless, even with these enhancements the transition to the Slice of Day framework alone will not address the tight RA market conditions projected through 2026.

10. Challenges With New Resource Uncertainty

New resources bring new challenges. The RA program allows a new resource to count in the Year-Ahead process from the month of its expected on-line date. However, if the resource fails to reach commercial operation at that date, the resource may not be counted in the Month-Ahead process and the LSE must find a different resource to meet their RA needs. The challenge this presents is that an LSE is unlikely to sell any excess RA in the Year-Ahead process if that excess

[35] LSE's can determine their planned storage dispatch. For this analysis, CalCCA developed a simple optimization model to determine the best way to charge and discharge storage.

is contingent on a new resource achieving commercial operation. Why sell off excess resources only to find the new resource did not come on-line and have to buy another resource at potentially a higher price than the excess was sold for? In addition, it is becoming relatively common for entities to offer sales of capacity contingent on the new resource achieving commercial operation. That is, a seller that is long capacity if the new resource comes online will sell the excess contingent on the resource achieving commercial operation and thus move the non-compliance risk to the buyer.

Much like the hydroelectric discussion in Section 6, the availability of new build expected to come on-line in a compliance year is likely more constrained than the Month-Ahead process when the commercial operation date is known. To the extent the resource has come on-line, the LSE is now willing to sell excess RA so that their customers get the value of the resource without a risk that it will make them non-compliant with their RA requirements.

The only way to ease the current capacity constraints of the RA market is to continue to build new resources. However, this new build is likely to ease constraints in the Month-Ahead RA market and not in the Year-Ahead market due to the uncertainty of achieving commercial operation from the resource.

11. Conclusion

The supply of resource adequacy left only a razor-thin margin to meet 2023 demand. The tightness in the market made it difficult, if not impossible, for all LSEs to comply with year-ahead requirements, and the tight conditions carried into month-ahead compliance. 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. In addition, the potential variability of RA supply between Year-Ahead and Month-Ahead RA showings creates a new issue that must be recognized in the RA program.

Seven interim actions should be considered.

1) Expressly recognize the tight RA supply conditions and its consequences in the CPUC's next RA decision.
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) Consider the potential for waiving Year-Ahead penalties if an LSE meets its obligation in the Month-Ahead showing.
4) 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.
5) 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.

6) 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.

7) Test and evaluate the new Slice of Day RA model to ensure that:

   a. There are sufficient resources to be able to meet the new RA accounting mechanism. If there are not, then the Commission must examine what must be done to obtain a fleet capable of meeting the need before implementing penalties for RA deficiencies if the current fleet is incapable of meeting the reliability need.

   b. Evaluate the need for transactability adjustments in the Slice of Day mechanism. As discussed in Section 8, the ability to meet the requirements of the entire system from all resources is just the first step. While necessary, it is not sufficient to ensure effective compliance. To be sufficient, the Slice of Day mechanism must consider effective and efficient mechanism to enable parties to transact to meet individual compliance obligations which will also ensure that the total reliability need is met.

California Community Choice Association

SUBMITTED 12/04/2023, 02:09 PM

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

1. Please provide your organization’s comments on the Recommended Reliability Projects less than $50 million for the North Region.

The California Community Choice Association (CalCCA) has no comments at this time.

2. Please provide your organization’s comments on the Recommended Reliability Projects less than $50 million for the South Region.

CalCCA has no comments at this time.

3. Please provide your organization’s comments on the MIC Expansion Requests.

CalCCA appreciates the California Independent System Operator’s (CAISO) presentation on the maximum import capability (MIC) expansion requests. The availability of MIC is critical for meeting a variety of load-serving entity (LSE) compliance obligations. Both Resource Adequacy (RA) and Integrated Resource Plan (IRP) procurement obligations require LSE to obtain MIC for the portions of their obligations being met by out-of-state (OOS) resources. In addition, the California Public Utilities Commission (CPUC) has relied upon significant amounts of OOS wind in its preferred system plans (PSP) that will require MIC to ensure deliverability to CAISO load. LSEs and developers may be understandably hesitant to invest in the development of new OOS resources when there is significant uncertainty that those resources will count towards their compliance obligations due to the lack of MIC in both the short and long-term. For these reasons, the CAISO should aim to provide as much transparency as possible within the MIC expansion request process so that LSEs have a clear picture of when, where, and how much total import capability will grow in response to the CPUC’s PSP portfolio.

The CAISO should adopt the following enhancements to increase MIC expansion transparency:

- **Provide Details Regarding MIC Expansions Driven by the CPUC Portfolio:** The CAISO did not study several MIC expansion requests because the requests overlapped with the CPUC portfolio. With the current level of information available to stakeholders, the overlap with MIC expansion requests and the CPUC portfolio is unclear. For example, the “On-Peak Eldorado – McCullough 500 kV constraint summary” on slide 83 includes details on the affected interties, the megawatts (MW) of MIC expansion request behind the constraint, and the amount of deliverable MIC expansion request MW. The presentation does not, however, provide a breakdown of the overlapping CPUC portfolio’s MIC expansion that is impacted by the constraint or enabled by the mitigation. In its presentation of policy-driven Transmission Planning Process (TPP) results, the CAISO should provide expected aggregate MIC expansion in MW by intertie from the combined impact of MIC expansion requests <u>and</u> the CPUC portfolio and their dependency on upgrades or mitigation.
- **Update MIC Advisory Estimates with Future Expansion:** The CAISO’s long-term advisory estimates for import capability are very useful in understanding the future availability of future long-term MIC. The CAISO should regularly update these advisory estimates with the amount of MIC that can be expanded resulting from the CPUC’s portfolio, when that MIC expansion will take place, and the proposed mitigation or upgrade that will enable the MIC expansion. Given the PSP’s reliance on out-of-state resources, the CAISO should seek to provide stakeholders with a clear picture of how total import capability will grow so LSEs and developers can move forward with enough certainty to minimize the risk associated with securing MIC.
- **MIC Associated with Non-CAISO Transmission Element Entitlements:** The CAISO should clarify if there is any MIC or modeled transmission in the CAISO model that is based upon an entitlement to a non-CAISO transmission element that, if the entitlement expired, would no longer be available to the CAISO? If so, the CAISO should explain how many MWs are tied to these entitlements and at what locations. The

CAISO should also explain when the entitlements expire and the expected process for informing the TPP and MIC allocation process of these expirations to ensure that they can be accounted for in the CAISO and CPCU's planning processes.

The CAISO's assessment of MIC expansion requests indicates that, given the current transmission system, a vast majority of the MIC expansion requests studied by the CAISO failed the TPP deliverability study, meaning the CAISO cannot expand MIC. MIC expansion would necessitate transmission upgrades due to a lack of available deliverability. If a MIC expansion request results in a "fail" of the CAISO's deliverability assessments, the CAISO must (1) expand MIC after the completion of transmission upgrades that could result in additional deliverability for MIC expansion requests that overlap with the CPUC portfolio or (2) provide a feedback loop to the CPUC of MIC expansion requests that failed but were not included in the CPUC portfolio such that the CPUC can use those requests to inform future base case resource portfolios for study in the next TPP cycle. The CAISO has stringent requirements for studying MIC expansion requests (*e.g.*, LSE demonstration of an executed contract), so the CPUC should take MIC expansion requests as an indication that there are high levels of commercial interest in the resources at those locations. As a result, the CPUC should include them as part of its base portfolios for determining policy-driven transmission. Mitigation alternatives should be selected that enable the MIC expansion requests to receive full deliverability. This step is essential to provide off-takers certainty on project viability and developers the confidence to move forward with providing resources that are critical to meeting California's climate and reliability goals.

4. Please provide your organization's comments on the Preliminary Policy Assessment Results for the SCE & GLW areas.

CalCCA has no comments at this time.

5. Please provide your organization's comments on the Preliminary Policy Assessment Results for the SDG&E area

CalCCA has no comments at this time.

6. Please provide your organization's comments on the Preliminary Policy Assessment Results for the PG&E area.

In some cases, the CAISO's policy assessment results do not identify any area-scale deliverability constraints even though the 2023 generator interconnection and deliverability allocation procedures (GIDAP) resulted in no deliverability allocations in the region to due existing constraints (e.g., North of Greater Bay or Greater Bay Areas). To ensure that valuable clean capacity that is mapped by the CPUC and under contract with LSEs is not put at risk, the CAISO should:

- Clarify why the GIDAP and TPP results differ with respect to the identification of area-scale deliverability constraints; and
- Either provide confidence that the 2024 GIDAP will align with the TPP results or expand the scope of upgrades so that they will align.

7. Please provide your organization's comments on the Preliminary Economic Analysis Results.

CalCCA has no comments at this time.

8. Please provide any additional comments on the November 16, 2023 Transmission Planning Process Stakeholder Meeting.

In its evaluation of Humboldt offshore wind mitigation alternatives, the CAISO will evaluate reinstating 500 kilovolts (kV) ratings that had previously been derated. Given the impacts deratings may have on deliverability and the need for upgrades, the CAISO should provide transparency on past 500 kV de-rates, studies that have been impacted by the de-rates (past TPPs, GIDAPs, etc.), and the potential and necessary criteria for reinstating 500 kV ratings.

**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' REPLY COMMENTS ON THE PROPOSED DECISION DIRECTING CERTAIN INVESTOR-OWNED UTILITIES' DEMAND RESPONSE PROGRAMS, PILOTS, AND BUDGETS FOR THE YEARS 2024-2027

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December 5, 2023

On behalf of the Joint Community Choice Aggregators

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TABLE OF AUTHORITIES

Rules of Practice and Procedure

Rule 14.3 1

SUMMARY OF RECOMMENDATIONS

- The Commission should not require Pacific Gas & Electric Company (PG&E) to modify Schedule E-CCAINFO and the associated NDA, and should instead direct PG&E, and all IOUs, to develop a separate non-disclosure agreement (NDA) covering customer demand response (DR) program participation data in coordination with community choice aggregators (CCA).
- The Commission should not adopt a blanket DR program enrollment requirement in this proceeding, and should instead explore such a requirement on a case-by-case basis in other proceedings.

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' REPLY COMMENTS ON THE PROPOSED DECISION DIRECTING CERTAIN INVESTOR-OWNED UTILITIES' DEMAND RESPONSE PROGRAMS, PILOTS, AND BUDGETS FOR THE YEARS 2024-2027

The Joint Community Choice Aggregators[1] (Joint CCAs) submit these reply comments on the *Proposed Decision Directing Certain Investor-Owned Utilities' Demand Response Programs, Pilots, and Budgets for the Years 2024-2027* (PD) pursuant to Rule 14.3 of the Rules of Practice and Procedure of the California Public Utilities Commission and the Administrative Law Judge's November 22 Email Ruling Granting Extension of Time for Opening and Reply Comments for Phase II DR Proposed Decision.

The Joint CCAs address two issues in these reply comments. First, the Joint CCAs recommend the Commission reject Pacific Gas & Electric Company's (PG&E) proposal to modify Schedule E-CCAINFO and the associated non-disclosure agreement (NDA).[2] The Commission can ensure customer demand response (DR) program participation data remains protected without requiring tariff modifications by directing PG&E (and other IOUs as the need arises) to enter into

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).

2 PG&E Opening Comments on the PD at 10.

a separate NDA covering the exchange of DR program participation data specifically with community choice aggregators (CCA). Second, the Joint CCAs request the Commission uphold the PD's rejection of PG&E's proposed blanket DR program enrollment requirement for participants in technology incentive programs, and reject the California Efficiency + Demand Management Council, Leapfrog Power, Inc., and OhmConnect, Inc.'s support for PG&E's proposal.[3] Implementing a blanket DR program enrollment requirement would be premature in this proceeding. The Commission should consider any such requirement on a case-by-case basis to avoid inadvertent harm to customers and conflicts between program requirements.

I. REPLY COMMENTS

A. The Commission Can Ensure Customers' Data is Protected Without Directing Modifications to Schedule E-CCAINFO and the associated NDA as PG&E Proposes.

The PD directs PG&E to "share enrollment information of CCA customers directly enrolled in PG&E's ELRP sub-groups A.1 and A.6 with the CCAs requesting such information for their customers, for the purposes of CCA load forecasting and resolving potential dual enrollment issues between ELRP and programs managed by the CCAs."[4] While the Joint CCAs generally support this data-sharing directive, the Joint CCAs recommend a series of minor modifications to strengthen and broaden that directive (*see* Joint CCAs' Opening Comments on the PD at 3-6).

PG&E does not object to Commission's data-sharing directive and agrees it "would provide the information to the CCA, as the unbundled customer's load serving entity (LSE)."[5] PG&E asserts, however, that the Commission should require CCAs to enter into an NDA covering

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[3] California Efficiency + Demand Management Council, Leapfrog Power, Inc., and OhmConnect, Inc.'s Opening Comments on the PD at 3-4.

[4] PD at 179.

[5] PG&E Opening Comments on the PD at 10.

the ELRP customer-specific data, and to that end, recommends modifications to Schedule E-CCAINFO and the associated NDA No. 79-1031 (an overarching NDA under which PG&E currently provides certain customer specific data to CCAs for billing and related purposes).[6]

The Joint CCAs agree that maintaining the safety of customer data is an important objective, but recommend a more administratively efficient alternative to PG&E's proposal. PG&E should follow the example developed to allow the exchange of customer data related to enrollment in energy efficiency (EE) programs in order to prevent dual enrollment. To exchange EE program participation data, Marin Clean Energy (MCE) (a CCA and EE program administrator) and PG&E developed an EE-specific NDA (attached to these reply comments as Attachment A),[7] rather than updating the Schedule E-CCAINFO tariff or the associated NDA 79-1031. The Commission should direct PG&E to develop a similar NDA specific to DR programs in coordination with CCAs, or simply revise the existing EE NDA to cover DR program-related data. This directive would avoid requiring PG&E to modify a tariff simply to facilitate the exchange of a relatively limited volume of DR program-related data. While the issues described here have not been raised by CCAs in other IOU service territories, the Joint CCAs request that the Commission extend the NDA directive to all IOUs to proactively address similar data-sharing needs that are certain to arise in other IOU territories in the future.

B. The PD Correctly Denies PG&E's Proposal to Implement an Automatic DR Program Enrollment Requirement.

PG&E proposed that the Commission develop an automatic DR program enrollment requirement for customers receiving ratepayer-funded technology incentives, such as those available via energy efficiency, clean energy transportation and distributed generation.[8] The PD

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6 PG&E Opening Comments on the PD at 10.
7 In the attached, Appendix A of the EE NDA was removed due to confidentiality.
8 PG&E-2 at 2-11:2-14.

correctly denies this proposal, noting Cal Advocates' concerns that PG&E's proposal "could have negative bill impacts on low-income or medically vulnerable customers, or any others that do not understand how the DR programs operate."[9]

In comments on the PD, the California Efficiency + Demand Management Council, Leapfrog Power, Inc., and OhmConnect, Inc. argue "[p]roviding incentives to customers to qualify for technologies that are capable of providing DR should entail a *requirement* to provide DR."[10] The Joint CCAs disagree with this blanket statement. While the Joint CCAs are generally open to establishing DR program enrollment requirements in other proceedings,[11] the Commission should develop any DR program enrollment requirement associated with participation in technology incentive programs on a case-by-case basis in the respective proceedings for the technology incentive program. A DR program enrollment requirement can create several implementation-related challenges unique to each technology incentive program. Among them, program administrators will have to determine how program impacts (e.g., energy savings, demand savings, and others) will be measured and assigned between programs,[12] and how the potentially conflicting goals of technology incentive and DR programs might be reconciled.[13] In order to avoid inadvertent customer harm and confusion, the Commission should carefully consider each of these implementation-related challenges in separate proceedings, and should not direct a blanket DR program enrollment requirement before doing so.

9 PD at 35, citing CalAdvocates-1 at 2-3:24-2-4:12.

10 California Efficiency + Demand Management Council, Leapfrog Power, Inc., and OhmConnect, Inc.'s Opening Comments on the PD at 4.

11 E.g. the Self-Generation Incentive Program and associated DR requirements.

12 For instance, if a customer enrolls in a peak demand focused EE program, and is required to enroll in a DR program, the incrementality rules applied to energy savings and demand reductions during peak hours will require clarification.

13 For instance, whereas a DR program may prioritize peak demand reduction, a technology incentive program may prioritize GHG reductions—incentivizing a different set of customer behaviors.

II. CONCLUSION

The Joint CCAs continue to respectfully request the Commission revise the PD consistent with Appendix A to the Joint CCAs' Opening Comments on the PD, and adopt the other recommendations discussed in the Joint CCAs' Opening and Reply Comments on the PD.

Respectfully submitted,

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December 5, 2023

Attachment A to Joint CCA Reply Comments

on Proposed Decision in A.22-05-002 et al.

MUTUAL NONDISCLOSURE AGREEMENT BETWEEN PACIFIC GAS AND ELECTRIC COMPANY AND MARIN CLEAN ENERGY FOR SHARING ENERGY EFFICIENCY PROGRAM DATA

1. Purpose. The purpose of this Agreement is to permit Marin Clean Energy ("MCE") and Pacific Gas and Electric Company ("PG&E"), respectively, (MCE and PG&E, individually referred to herein as either the "Disclosing Party" or "Receiving Party," as applicable, and together as the "Parties") to use Confidential Information disclosed by the Disclosing Party to enable Receiving Party to more efficiently administer its Energy Efficiency program ("EE Program") for the sole purpose of determining whether customers are participating or have participated in the EE programs and projects of either Party. The Confidential Information shall not be used for any other purpose.

2. Terms and Conditions. The Receiving Party and its employees, agents, representatives and subcontractors shall protect Disclosing Party's Confidential Information by fully complying with the confidentiality, information security and intellectual property provisions attached as Appendix A to this Agreement.

3. Term of Agreement. This Agreement will commence on the last date of the signature page and will continue in effect until all of the Confidential Information (as defined herein) has been destroyed or returned to Disclosing Party.

MCE		PG&E	
Name	Vicken Kasarjian	Name	Eva Chu
Signature		Signature	
Title	COO	Title	Manager, EE Programs
Date	11/15/2019	Date	11/21/2019

Exhibit B

Confidentiality and Data Security

1. In addition to the requirements set out in Section 1.3 of Exhibit A of the Agreement, RECEIVING PARTY shall comply with the following additional terms of this Exhibit B (Confidentiality and Data Security) regarding the handling of Confidential Information from DISCLOSING PARTY or its customers.

2. NON-DISCLOSURE AGREEMENTS: RECEIVING PARTY shall have all of its subcontractors who have access to Confidential Information pursuant to this Agreement sign a non-disclosure agreement in the form attached hereto as Exhibit C (Non-disclosure and Use of Information Agreement "NDA"). Prior to receiving Confidential Information from DISCLOSING PARTY, RECEIVING PARTY shall promptly furnish the original signed non-disclosure agreements to DISCLOSING PARTY.

3. SECURITY MEASURES: RECEIVING PARTY shall take "Security Measures" with the handling of Confidential Information to ensure that the Confidential Information will not be compromised and shall be kept secure. Security Measures shall mean industry standards and techniques, physical and logical, including but not limited to:
    a. written policies regarding information security, disaster recovery, third-party assurance auditing, penetration testing,
    b. password protected workstations at RECEIVING PARTY's premises, any premises of any person who has access to such Confidential Information,
    c. encryption of Confidential Information, and
    d. measures to safeguard against the unauthorized access, destruction, use, alteration or disclosure of any such Confidential Information including, but not limited to, restriction of physical access to such data and information, sanitization or destruction of media, and establishment of an information security program.

4. COMPLIANCE AND MONITORING: Prior to DISCLOSING PARTY's first transfer of Confidential Information to RECEIVING PARTY, RECEIVING PARTY shall comply with security policies relating to the handling of Confidential Information as described above.
    a. In the event, DISCLOSING PARTY determines RECEIVING PARTY has not complied with Security Measures, DISCLOSING PARTY shall provide written notice to RECEIVING PARTY describing the deficiencies. RECEIVING PARTY shall then have sixty (60) calendar days to cure. If RECEIVING PARTY has not cured the deficiencies within sixty (60) calendar days, DISCLOSING PARTY may cancel this Agreement for cause in accordance with Section 8.2 of these General Conditions.

5. SECURITY OF DISCLOSING PARTY CONFIDENTIAL INFORMATION: RECEIVING PARTY agrees that RECEIVING PARTY's collection, management and use of DISCLOSING PARTY Confidential Information during the Term shall comply with these security requirements and all applicable laws, regulations, directives, and ordinances.

   a. Vendor Security Review: Before receiving any DISCLOSING PARTY Confidential Information, RECEIVING PARTY shall undergo DISCLOSING PARTY's Vendor Security Review process.

6. SECURITY BREACH: RECEIVING PARTY shall as soon as practicable notify DISCLOSING PARTY in writing of any unauthorized access or disclosure of Confidential Information and/or DISCLOSING PARTY Confidential Information.
   a. If requested in advance and in writing by DISCLOSING PARTY, RECEIVING PARTY will notify the potentially affected persons regarding such breach or potential breach within a reasonable time period determined by DISCLOSING PARTY and in accordance with any applicable law. In addition, in no event shall RECEIVING PARTY issue or permit to be issued any public statements regarding the security breach involving Confidential Information unless DISCLOSING PARTY requests RECEIVING PARTY to do so in writing, or RECEIVING PARTY is required to do so by law.

7. RIGHT TO SEEK INJUNCTION: The Parties agree that any breach of this Exhibit B (Confidentiality and Data Security) would constitute irreparable harm and significant injury to the DISCLOSING PARTY. Accordingly, and in addition to the Parties' right to seek damages and any other available remedies at law or in equity for a breach of and in accordance with this Agreement, the Parties agree that either Party, if the DISCLOSING PARTY, will have the right to obtain, from any competent civil court, immediate temporary or preliminary injunctive relief enjoining any breach or threatened breach of this Agreement, involving the alleged unauthorized access, disclosure or use of any Confidential Information. Each Party, in its role as the RECEIVING PARTY, hereby waives any and all objections to the right of such court to grant such relief, including, but not limited to, objections of improper jurisdiction or forum non convenience.

8. CPUC and IOU DISCLOSURE: Notwithstanding anything to the contrary contained herein, but without limiting the general applicability of the foregoing, RECEIVING PARTY understands, agrees and acknowledges as follows.
   a. DISCLOSING PARTY hereby reserves the right in its sole and absolute discretion to disclose any and all terms of this Agreement and all exhibits, attachments, and any other documents related thereto to the California Public Utilities Commission (CPUC), and that the CPUC may reproduce, copy, in whole or in part or otherwise disclose the Agreement to the public.

9. SUBPOENAS: In the event that a court or other governmental authority of competent jurisdiction, including the CPUC, issues an order, subpoena or other lawful process requiring the disclosure by RECEIVING PARTY of the Confidential Information provided by DISCLOSING PARTY, RECEIVING PARTY shall notify DISCLOSING PARTY immediately upon receipt thereof to facilitate DISCLOSING PARTY's efforts to prevent such disclosure, or otherwise preserve the proprietary or confidential nature of the Confidential Information.

Exhibit C

Non-disclosure and Use of Information Agreement ("NDA")

THIS AGREEMENT is by and between the undersigned contractor of Marin Clean Energy ("MCE"), and PACIFIC GAS AND ELECTRIC COMPANY (MCE and PG&E, and each of their authorized employees, agents, contractors or representatives subject to this NDA, are referred herein as individually either the "Disclosing Party" or "Receiving Party," as applicable, and together, the "Parties"). The Parties agree as follows:

1. The Receiving Party acknowledges that in the course of implementing the EE Program, the Receiving Party will be given access to certain Confidential Information, as defined in Section 1.3 of the Mutual Nondisclosure Agreement between Pacific Gas and Electric Company and MCE for Sharing EE Program Data ("Agreement"). The Receiving Party has read the Agreement and agrees to abide by the terms of the Agreement.
2. In consideration of being made privy to such Confidential Information (as defined in the Agreement), the Receiving Party hereby shall hold the same in strict confidence, and not disclose it, or otherwise make it available, to any person or third party (including but not limited to any affiliate of DISCLOSING PARTY that produces energy or energy-related products or services) without the prior written consent of DISCLOSING PARTY. The Receiving Party agrees that all such Confidential Information:
    a. Shall be used only for the purpose specified in Section 1 of the Mutual Nondisclosure Agreement; and
    b. Shall, together with any copies, reproductions or other records thereof, in any form, and all information and materials developed by Undersigned there from, be deleted, destroyed or returned to DISCLOSING PARTY when no longer needed by the Receiving Party related to the EE Program.
3. The Receiving Party hereby agrees that any third parties owning any Confidential Information are express third party beneficiaries of this Agreement.
4. The Receiving Party hereby acknowledges and agrees that because (a) an award of money damages is inadequate for any breach of this Agreement by the Receiving Party or any of its representatives and (b) any breach causes DISCLOSING PARTY irreparable harm, that for any violation or threatened violation of any provision of this Agreement, in addition to any remedy DISCLOSING PARTY may have at law, DISCLOSING PARTY is entitled to equitable relief, including injunctive relief and specific performance, without proof of actual damages.

5. This Agreement shall be governed by and interpreted in accordance with the laws of The State of California, without regard to its conflict of laws principles.

RECEIVING PARTY

By: [signature]

Name: Vicken Kasarjian

Title: COO

Company MCE

Date: 11/15/2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company For Adoption of Electric Revenue Requirements and Rates Associated with its 2024 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U 39 E)	Application No. 23-05-012 (Filed May 15, 2023)
Expedited Application of Pacific Gas and Electric Company Pursuant to the Commission's Approved Energy Resource Recovery (ERRA) Trigger Mechanism. (U 39 E)	Application No. 23-07-012 (Filed July 28, 2023)

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING COMMENTS ON PROPOSED DECISION

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December 5, 2023

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SUMMARY OF RECOMMENDATIONS

- The Commission should direct Pacific Gas & Electric Company (PG&E) to apply banked Renewable Energy Credits (REC) towards its 2024 Minimum Retained Renewable Portfolio Standard (RPS) requirement on a "first-in first-out" (FIFO) basis consistent with the California Community Choice Association's (CalCCA) proposed methodology and to make correcting entries to the 2023 Portfolio Allocation Balancing Account (PABA) to reflect that methodology.

- The Commission should direct PG&E to amortize its 2023 year-end Incremental Energy Resource Recovery Account (ERRA) Trigger Balance over twelve months effective January 1, 2024.

- The Commission should remove references to CalCCA in its discussion of PG&E's 2024 Sales Forecast because CalCCA did not take a position on that issue in this proceeding.

- The Commission should adopt CalCCA's recommended modifications to the PD's findings of fact, conclusions of law, and ordering paragraphs reflected in Appendix A to these comments.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company For Adoption of Electric Revenue Requirements and Rates Associated with its 2024 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U 39 E)	Application No. 23-05-012 (Filed May 15, 2023)
Expedited Application of Pacific Gas and Electric Company Pursuant to the Commission's Approved Energy Resource Recovery (ERRA) Trigger Mechanism. (U 39 E)	Application No. 23-07-012 (Filed July 28, 2023)

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
OPENING COMMENTS ON PROPOSED DECISION

The California Community Choice Association[1] (CalCCA) submits these comments on the *Proposed Decision Adopting the Electric Revenue Requirements and Rates Associated With the 2024 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation and the 2024 Electric Sales Forecast for Pacific Gas and Electric Company as well as the Resolution of the 2023 Trigger*

[1] California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Ava Community Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, Energy For Palmdale's Independent Choice, Lancaster 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.

Application for an Undercollection of the Energy Resource Recovery Account (PD) pursuant to Rule 14.3 of the Rules of Practice and Procedure of the California Public Utilities Commission and the modified procedural schedule established in Administrative Law Judge (ALJ) Long's November 20, 2023 E-mail Ruling re Modification of the Procedural Schedule in A.23-05-012 et al.

I. INTRODUCTION

CalCCA appreciates the ALJ's efforts in resolving the complicated and wide-ranging issues raised in this consolidated proceeding on an expedited timeline. These opening comments focus on two issues: (1) Pacific Gas and Electric Company's (PG&E) use of banked Renewable Energy Credits (REC) to cover a shortfall in its 2024 Minimum Retained Renewable Portfolio Standard (RPS) and (2) PG&E's proposal to amortize up to $256 million of its Incremental Energy Resource Recovery Account (ERRA) Trigger balance over a six-month period.

With respect to the first issue, the PD commits factual and legal error where it finds PG&E's proposed "Last-In First-Out" (LIFO) banked REC application methodology "is consistent with prior decisions and the very recent Southern California Edison Company 2024 ERRA Forecast proposed decision."[2] In fact, prior Commission decisions (including the recent decision in Southern California Edison's (SCE) 2024 ERRA Forecast case[3]) do not adopt a LIFO methodology. Reversing this finding to adopt CalCCA's recommended FIFO methodology is both logical and fair because it prioritizes customers who were the earliest to pay for PG&E's excess RPS procurement and therefore have been waiting the longest for credits.

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2 PD at 17.

3 Application (A.) of Southern California Edison Company (U 338-E) for Approval of its 2024 ERRA Forecast Proceeding Revenue Requirement, A.23-06-001, Decision (D.) 23-11-094 (Nov. 30, 2023).

With respect to the second issue, the PD adopts a six-month amortization period for PG&E's Incremental ERRA Trigger balance, finding a six-month cycle "reduces accrued carrying costs (interest) on the balancing account and enhances PG&E's liquidity position."[4] While CalCCA appreciates that prolonged undercollections lead to the accumulation of interest on the balancing account, PG&E has not presented the incremental carrying costs associated with amortizing its Trigger balance over an additional six months, nor demonstrated those costs outweigh the adverse impact of a steeper rate increase on bundled customers for the first six months of 2024. Moreover, as the PD recognizes, a twelve-month amortization allows PG&E's balance "to be more evenly spread across the ebbs and flows of both seasonal consumption patterns and seasonal energy cost fluctuations."[5] The Commission should adopt a twelve-month amortization because it balances PG&E's need for timely cost recovery with the objective of rate stability and is consistent with the Commission's approach to the amortization of PG&E's ERRA trigger balance in prior years.

Finally, CalCCA requests the Commission remedy a series of incorrect references to CalCCA in Section 8 of the PD's *dicta.*

II. COMMENTS

A. The PD Commits Factual and Legal Error Where it States PG&E's Last-In First-Out (LIFO) Methodology is Consistent with Prior Commission Decisions.

In this proceeding, PG&E proposes to apply excess "banked" RECs from prior years to meet its Minimum Retained RPS obligations for the forecast year (2024); charge current bundled customers for those RECs in the forecast year; and use the forecast year RPS market price

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4 PD at 16.

5 *Id*.

benchmark to credit the Portfolio Allocation Balancing Account (PABA), with the credit applied to vintage years based on the year the RECs were generated. Each of those proposals is not only consistent with PG&E's approach in last year's ERRA Forecast case (A.22-05-029), but is also reasonable and compliant with applicable rules, regulations and prior Commission decisions. CalCCA therefore agrees with each of those proposals and supports the PD's approval of those proposals.[6] CalCCA recommends the Commission adopt findings of fact, conclusions of law and ordering paragraphs addressing these proposals (*see* Appendix A to these comments).

PG&E and CalCCA disagree, however, on one narrow but important aspect of PG&E's proposal to apply banked RECs towards its 2024 Minimum Retained RPS requirement. Whereas PG&E proposes to apply the newest, most recent vintages of RECs first (a "Last-In First-Out" or "LIFO" methodology), CalCCA recommends PG&E start by crediting the customers who have been waiting the longest (a "First-In First-Out" or "FIFO" methodology).

The fundamental distinction between the FIFO and LIFO approaches is the sequence in which specific customer vintages receive credits for the excess RECs they previously funded. CalCCA's recommended FIFO methodology would allow customers to receive a credit in the order in which they paid for PG&E's excess RPS procurement (*i.e.*, in 2024, vintages 2013, 2014, 2015 and 2016 would receive a credit).[7] Customers who were the earliest to pay for excess RPS procurement (vintage 2013), and have been waiting the longest for a credit, would be the first to benefit from PG&E's use of banked RECs. PG&E's preferred LIFO methodology, in contrast, favors more recent vintages (*i.e.*, in 2024, vintages 2018, 2020, 2021 and 2022 would receive a

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[6] PD at 16-17.

[7] CalCCA-01 at 18.

credit) and keeps customers who paid for banked RECs in earlier years waiting longer for a credit.[8]

Importantly, the sequence in which PG&E draws RECs banked in prior years will ultimately have no impact on either the total costs that PG&E's customers (bundled and unbundled) pay or the total credit those customers receive. Whether the Commission directs a LIFO or a FIFO approach, PG&E will eventually use all the RECs it banked in prior years, bundled customers will pay for those RECs, and customers (bundled and unbundled) who previously paid for those RECs will be credited.[9] PG&E itself forecasts that while it will continue leaning on its "bank" of excess RECs to meet RPS compliance requirements in the near-term,[10] it expects to exhaust that bank of excess RECs and procure RPS resources to meet its compliance obligations in the foreseeable future.[11] At that point, all customers who had previously paid for PG&E's excess RPS procurement would have received credits, whether PG&E used those RECs in a FIFO or LIFO sequence.

Further, whether the Commission ultimately approves a FIFO or LIFO methodology, the *total value* of banked RECs that PG&E will use to cover its 2024 Retained RPS shortfall will remain the same.[12] Again, the only difference between the impact of the two methodologies is when specific vintages of customers receive a credit.

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8 *Id*. at 12:1-12.

9 PG&E's reply comments on the Fall Update, in which the utility suggests a FIFO methodology would increase bundled customer costs, are therefore misleading. (Reply Comments of Pacific Gas and Electric Company (U-39 E) on Fall Update at 3-4). PG&E computes the impact of a FIFO methodology on the 2024 revenue requirement but does not mention that bundled customers will eventually receive the same credits under a FIFO methodology as they would receive under a LIFO methodology.

10 Rulemaking (R.) 18-07-003, Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewable Portfolio Standard Program, Pacific Gas and Electric Company's (U 39 E) Draft 2023 Renewable Energy Procurement Plan at 3 (Jul. 17, 2023).

11 *Id*. at 34-35.

12 CalCCA-01 at 18:1-4.

Notwithstanding the FIFO methodology's inherent fairness and logic relative to LIFO, the PD adopts PG&E's preferred LIFO method based on the incorrect factual and legal finding that LIFO "is consistent with prior decisions and the very recent Southern California Edison Company 2024 ERRA Forecast proposed decision."[13] The PD errs and should be reversed. No prior Commission decision—including D.22-12-044 resolving PG&E's 2023 ERRA Forecast application and the recent decision in SCE's 2024 ERRA Forecast proceeding—adopts a LIFO methodology for the application of banked RECs.

In D.22-12-044, the Commission approved PG&E's proposal to apply 2021 and 2022 banked RECs towards its 2023 Minimum Retained RPS shortfall. PG&E did not use those banked RECs in a LIFO sequence (*i.e.*, exhaust 2022 banked RECs before moving on to 2021 banked RECs). Instead, PG&E drew from both 2021 and 2022 RECs in proportion to its RPS generation surplus in each year.[14] Thus, D.22-12-044 does not support, let alone require, the PD's directive that PG&E apply a LIFO methodology.

In SCE's 2024 ERRA Forecast proceeding, the Proposed Decision (Rev.1), adopted at the Commission's November 30, 2023 business meeting, directs SCE to utilize all available banked RECs generated in 2019 or later (post-2018 RECs) before using any RECs generated before 2019.[15] Contrary to the PD's finding, the Commission did not direct SCE to apply those post-2018 RECs in a LIFO sequence. In fact, as CalCCA pointed out in this proceeding, SCE proposed to apply its banked RECs to cover its forecasted Retained RPS shortfall in 2024 on a <u>FIFO</u> basis.[16]

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[13] PD at 17; Finding of Fact (FOF) 5.

[14] PG&E-01 at 9-20:20-26 (describing PG&E's 2023 banked REC application methodology).

[15] A.23-06-001, Proposed Decision (Rev. 1) at 51-52; D.23-11-094 at 60; FOF 44, Conclusion of Law 5, Ordering Paragraph 9.

[16] CalCCA Opening Brief at 12; CalCCA-03 (SCE testimony from its 2024 ERRA Forecast proceeding, A.23-06-001, describing its banked REC application methodology); *see also* D.23-11-094 at

No other Commission decision adopts a LIFO methodology for the use of banked RECs. Thus, the PD's sole basis for adopting a LIFO methodology is factually and legally incorrect. The Commission should therefore modify the PD's conclusion on this issue and direct PG&E to apply banked RECs towards its 2024 Minimum Retained RPS shortfall on a FIFO basis. To the extent the Commission wishes to adopt an approach that is consistent with its prior decisions, including the recent decision in SCE's 2024 ERRA Forecast Proceeding, it should direct PG&E to prioritize the use of RECs generated in or after 2019 (post-2018 banked RECs), and to apply those RECs on a FIFO basis.

B. The Commission Should Adopt a 12-month Amortization Period for PG&E's ERRA Trigger Balance to Mitigate Rate Volatility and Avoid Imposing a Higher Rate Increase on Bundled Customers

PG&E proposes to recover up to $256 million of its outstanding ERRA balance, net of a relevant PABA balance (Incremental ERRA Trigger balance) over the first six months of 2024. The PD states that a six-month amortization period "reduces accrued carrying costs (interest) on the balancing account and enhances PG&E's liquidity position," but notes that a twelve-month amortization period "allows the costs to be more evenly spread across the ebbs and flows of both seasonal consumption patterns and seasonal energy cost fluctuations."[17]

While CalCCA does not object to PG&E's proposal to recover its Incremental ERRA Trigger Balance through a rate increase, PG&E's requested six-month amortization period is unusual and will steepen the rate increase that bundled customers experience as a result of this proceeding. In multiple past ERRA Trigger Applications, PG&E has rolled its year-end undercollection (or overcollection) into the following year's rates (and therefore amortized its

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59-60 (describing CalCCA and SCE stipulation illustrating that whereas PG&E proposed to use banked RECs on a LIFO basis, SCE proposed using those RECs on a FIFO basis).

[17] PD at 16.

Trigger balance over twelve months).[18] A twelve-month amortization period avoids forcing bundled customers, who already face significant affordability pressures, to absorb a steeper rate increase for the first six months of 2024. Moreover, a twelve-month amortization period, effective January 1, minimizes rate volatility, customer confusion, and incremental administrative burden because it is coincident with rates implemented through the Annual Electric True-Up (AET). In contrast, PG&E's proposed six-month amortization period increases rate volatility for bundled customers (as well as associated customer confusion and administrative burdens) by adding a mid-year generation rate change to the series of other rate changes PG&E will implement over the next twelve months (including, for example, rate changes resulting from its General Rate Case).

CalCCA therefore recommends the Commission follow the approach it has adopted in previous ERRA Trigger applications and direct PG&E to recover its 2023 year-end Incremental ERRA Trigger Balance over twelve months by rolling that balance into 2024 rates. A twelve-month amortization satisfies the fundamental purpose of the trigger mechanism, which is to "balance the utilities['] need for timely cost recovery and the consequences of frequent rate adjustments on consumer behavior."[19]

C. Technical Corrections

In four instances in a single paragraph on page 15, the PD suggests that CalCCA took a position on PG&E's 2024 sales forecast.[20] CalCCA assumes the PD intended to reference the

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[18] *See, e.g.* D.23-05-010 (concluding that D.22-12-044 (approving PG&E's 2023 ERRA Forecast application) and PG&E's implementation of 2023 generation-related revenue requirements in electric rates through the Annual Electric True-Up disposed of PG&E's ERRA undercollection); D.20-11-029 (concluding PG&E's proposal to address its ERRA overcollection through its 2021 ERRA Forecast Application proceeding was reasonable); D.20-03-012 (concluding PG&E's proposal to address its estimated 2019 ERRA overcollection through its 2020 ERRA Forecast Application proceeding was reasonable).

[19] D.02-10-062, p. 71, FOF 24.

[20] PD at 15.

Small Business Utility Advocates (SBUA) in each of those instances, because CalCCA did not take a position on PG&E's 2024 sales forecast in this proceeding. The Commission should remedy this error in its decision.

III. CONCLUSION

CalCCA appreciates the Administrative Law Judge's efforts in resolving the complex issues in this expedited proceeding and respectfully requests the Commission adopt the revisions discussed in these comments and detailed in Appendix A, attached hereto.

Respectfully submitted,

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December 5, 2023

APPENDIX A

Pursuant to Rule 14.3(b) of the Commission's Rules of Practice and Procedure, CalCCA provides this Appendix setting forth proposed changes to the *Proposed Decision Adopting the Electric Revenue Requirements and Rates Associated With the 2024 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation and the 2024 Electric Sales Forecast for Pacific Gas and Electric Company as well as the Resolution of the 2023 Trigger Application for an Undercollection of the Energy Resource Recovery Account*, including proposed changes to the findings of fact, conclusions of law and ordering paragraphs. CalCCA's proposed revisions appear in underline and strike-through.

Findings of Fact

4. ~~PG&E's~~CalCCA's proposal for a ~~six~~twelve-month amortization of the ERRA Trigger balance will ~~reduce carrying costs and~~ result in a timely rate recovery, mitigate the bundled customer rate increase by spreading that rate increase over twelve months, and reduce rate volatility for PG&E's bundled customers.
5. The use of the ~~LIFO~~FIFO method, using the ~~newest~~oldest RECs first ~~is consistent with prior Commission decisions~~ensures customers who were the earliest to pay for PG&E's banked RECs will be the first to receive credits for those RECs.
X. Under PG&E's proposed methodology for meeting its 2024 Minimum Retained RPS obligations, PG&E would apply excess RECs from 2018, 2020, 2021 and 2022 towards that obligation.
X. Under PG&E's proposed methodology for meeting its 2024 Minimum Retained RPS obligations, PG&E would charge bundled customers at the 2024 RPS market price benchmark for the excess RECs it uses, and use the 2024 RPS market price benchmark to credit the PABA, with the credit applied to vintage years based on the year the excess RECs were generated.

Conclusions of Law

6. It is reasonable and within the Commission's discretion to order PG&E to apply the ~~newest~~oldest RECs first using the ~~LIFO~~FIFO methodology~~, consistent with prior Commission decisions on this issue~~.
7. It is reasonable to use the ~~Last~~First-In-First-Out methodology to the use of excess prior year RECs.
X. It is reasonable and consistent with prior Commission decisions, rules and regulations for PG&E to apply excess RECs from 2018, 2020, 2021 and 2022 to meet its Minimum Retained RPS obligations for the 2024 forecast year.
X. It is reasonable and consistent with prior Commission decisions, rules and regulations for PG&E to charge bundled customers in the forecast year at the RPS market price benchmark for the forecast year for those customers' use of excess RECs from 2018, 2020, 2021 and 2022.
X. It is reasonable and consistent with prior Commission decisions, rules and regulations for PG&E to use the forecast year RPS market price benchmark to credit the PABA for the use of excess RECs from prior years, with the credit applied to vintage years based on the year the excess RECs were generated.

Ordering Paragraphs

5. Pacific Gas and Electric Company shall apply a ~~Last~~First-In-First-Out methodology to the use of excess prior year renewable energy credits.
6. Pacific Gas and Electric Company shall amortize the Energy Resource Recovery Account's undercollected balance over a ~~six~~twelve-month period beginning January 1, 2024.
X. Pacific Gas and Electric Company shall apply excess prior year renewable energy credits to meet its Minimum Retained RPS obligations for the forecast year.
X. Pacific Gas and Electric Company shall charge bundled customers in the forecast year for their use of excess Renewable Energy Credits from prior years at the Renewable Portfolio Standard Market Price Benchmark for the forecast year.
X. Pacific Gas and Electric Company shall credit the Portfolio Allocation Balancing Account for its use of excess Renewable Energy Credits from prior years at the Renewable Portfolio Standard Market Price Benchmark for the forecast year, with the credit applied to vintage years based on the year the excess Renewable Energy Credits were generated.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U39E) for Review of the Disadvantaged Communities – Green Tariff, Community Solar Green Tariff and Green Tariff Shared Renewables Programs.	A.22-05-022
And Related Matters.	A.22-05-023 A.22-05-024

REPLY COMMENTS OF THE JOINT COMMUNITY CHOICE AGGREGATORS AND CITY AND COUNTY OF SAN FRANCISCO ON ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENTS ON ASPECTS OF NET VALUE BENEFIT TARIFF PROPOSAL

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December 7, 2023

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City and County of San Francisco

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U39E) for Review of the Disadvantaged Communities – Green Tariff, Community Solar Green Tariff and Green Tariff Shared Renewables Programs.	A.22-05-022
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I. INTRODUCTION

In accordance with the California Public Utilities Commission's ("CPUC or "Commission") *Administrative Law Judge's Ruling Setting Aside Submission of the Record to Seek Comments on Aspects of Net Value Benefit Tariff Proposal,* dated November 6, 2023 ("ALJ Ruling"), Clean Power Alliance of Southern California ("CPA"), the City and County of San Francisco, acting by and through its Public Utilities Commission ("CleanPowerSF"), East Bay Community Energy ("EBCE") [1], Lancaster Choice Energy ("LCE"), Marin Clean Energy ("MCE"), Peninsula Clean Energy Authority ("PCE"), Pico Rivera Innovative Municipal Energy ("PRIME"), San Diego Community Power ("SDCP"), San Jacinto Power ("SJP"), and San José

[1] Pending formal filing with the Commission of EBCE's name change to Ava Community Energy ("Ava"), Ava will continue to file as EBCE in this proceeding until further notice, and will be referenced as EBCE in this filing.

Clean Energy ("SJCE") (collectively, the "Joint Community Choice Aggregators" or "Joint CCAs") hereby submit these Reply Comments.

The Joint CCAs continue to emphasize the importance of properly considering and vetting all proposals in the instant proceeding. While the Joint CCAs understand the urgency induced by approaching deadlines for federal tax incentives, the Joint CCAs caution against incomplete review and urge that the Commission discern whether any new community renewable program is beneficial for ratepayers before adoption. Additionally, if the Coalition for Community Solar Access Net Value Billing Tariff ("NVBT") proposal is adopted, the Joint CCAs agree with numerous other parties that it would be prudent to adopt an individual project cap. The Commission should also recognize that it has discretion to determine the best methodology for calculating avoided costs for a new community renewable program. Finally, the Joint CCAs address the compensation of bundled versus unbundled customers under the NVBT proposal and clarify that investor-owned utilities ("IOUs") would not be responsible for compensating unbundled customers.

II. The Commission Should Ensure that a NVBT Proposal is Fully Considered and Vetted Prior to Adoption and Provides Benefits to Ratepayers.

The Joint CCAs urge the Commission to take the time necessary to fully vet all proposals for a new community renewable program. While the Joint CCAs recognize and understand the interest in taking advantage of federal funding, as noted by The Utility Reform Network ("TURN") in opening comments,[2] the Commission should not approve a new program without first determining that the program will benefit ratepayers, or without evaluating all elements of the program. As noted by the Public Advocates Office at the California Public

[2] Comments of The Utility Reform Network on Administrative Law Judge's Ruling Setting Aside Submission of the Record to Seek Comments on Aspects of Net Value Benefit Tariff Proposal ("TURN Opening Comments") at 1.

Utilities Commission ("Cal Advocates"), Assembly Bill ("AB") 2316 "does not require that the Commission establish a new community renewable energy program if the Commission determines that such a program does not benefit ratepayers."[3]

Furthermore, each program being considered in this proceeding should be considered on its own merit. The Joint CCAs emphasize that the adoption of a new community renewable program need not be preceded by the termination of the existing Green Access Programs ("GAPs"). AB 2316 does not require the termination of the existing GAPs prior to implementation of any new programs, nor does it require the evaluation of the existing programs and newly proposed programs in conjunction with one another.[4]

TURN's primary recommendation is to terminate the existing GAPs and authorize the creation of a new NVBT.[5] However, if the Commission determines that a new community renewable energy program is not beneficial to ratepayers, the Commission should choose not to adopt the program, regardless of potential federal funding. Additionally, any decision on the current GAPs should be independent of a Commission decision on a newly proposed community renewable program. As the Joint CCAs have mentioned in prior filings, AB 2316 allows for the continuation of the current GAPs, as well as the adoption of a new program.[6] The Joint CCAs urge the Commission to thoroughly review the NVBT proposal independent from the Commission's decision regarding existing GAPs.

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[3] Opening Comments of the Public Advocates Office on Administrative Law Judge's Ruling Setting Aside Submission of the Record to Seek Comments on Aspects of Net Value Billing Tariff Proposal ("Cal Advocates Opening Comments") at 1.

[4] *See* Opening Brief of the Joint Community Choice Aggregators and City and County of San Francisco ("Joint CCA Opening Brief") at 4; *see also* Reply Brief of the Joint Community Choice Aggregators and City and County of San Francisco ("Joint CCA Reply Brief") at 9.

[5] TURN Opening Comments at 1.

[6] *See* Joint CCA Reply Brief at 9.

III. The Commission Should Adopt a Cap for NVBT Projects if the NVBT Proposal is Adopted.

Multiple parties advocate for a NVBT project cap in opening comments ranging from a 3 MW project cap to a 5 MW cap.[7] The Joint CCAs agree that if the NVBT proposal is adopted, a project cap would be prudent. An individual project cap would ensure that the Commission approves a program supported by CCSA's analysis in the record, which assumes a 5 MW project size,[8] and avoids unintended consequences resulting from large NVBT projects that have not been evaluated or accounted for in the analysis.

IV. The Commission has Discretion to Determine How Avoided Costs Should be Calculated for a New Community Renewable Program.

The Joint CCAs have expressed concerns with the use of Distributed Energy Resources ("DER") Avoided Cost Calculator ("ACC")-based avoided costs for NVBT projects, and urge the Commission to recognize that the uniform application of the DER ACC is not appropriate for all NVBT projects.[9] CCSA claims that, except for the energy supply portion of credit valuation, AB 2316 legally "requires that ACC-based costs be used when calculating NVBT bill credits, including avoided generation capacity."[10] The Joint CCAs believe that the language in the statute

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[7] Opening Comments of Southern California Edison Company (U 338-E) on ALJ Ruling Setting Aside Submission of the Record to Seek Comments on Aspects of Net Value Benefit Tariff Proposal ("SCE Opening Comments") at 30 ("Any community renewables tariff should be limited to a maximum of 3 MW projects and small."); Cal Advocates Opening Comments at 4 ("If a community renewable energy program is adopted, the Commission should limit project sizes to between 500 kW and less than 5 MW."); Opening Comments of Pacific Gas and Electric Company (U 39 E) in Response to Administrative Law Judge's Ruling Setting Aside Submission of the Record to Seek Comments on Aspects of Net Value Benefit Tariff Proposal ("PG&E Opening Comments") at 14 ("If a community renewable energy program tariff were to be adopted, PG&E supports a five-MW project cap…").

[8] *See generally* Opening Comments of the Coalition for Community Solar Access on Administrative Law Judge's Ruling Setting Aside Submission of the Record to Seek Comments on Cost-Effectiveness Considerations.

[9] Joint CCA Opening Comments.

[10] Opening Comments of the Coalition for Community Solar Access on Administrative Law Judge's Ruling Setting Aside Submission of the Record to Seek Comments on Aspects of Net Value Billing Tariff Proposal ("CCSA Opening Comments") at 10.

is clear that the Commission should determine how avoided costs should be calculated, and the language does not require use of the DER ACC.

The statute provides that a new community renewable energy program, if established, shall "[p]rovide bill credits to subscribers based on the avoided costs of the program's facilities, as determined by the commission's methods for calculating the full set of benefits of distributed energy resources."[11] CCSA argues that "[i]n considering the 'methods for calculating the full set of benefits of distributed energy resources' the Legislature focused on the [ACC]," as in the Senate Floor Analysis on AB 2316, the ACC "is specifically identified and discussed."[12] However, the ACC is only discussed in the general background section of the Senate Floor Analysis, along with the existing community solar programs, and net energy metering.[13] In fact, the Joint CCAs believe that, had the Legislature wanted to specifically require the use of the DER ACC when calculating NVBT bill credits, the DER ACC would have been specifically stated in the bill language, as it was in the Senate Floor Analysis. Instead, the language calls for avoided costs "as determined by the commission's methods…."[14] This implies that the Legislature entrusted the Commission to determine the most appropriate methods for calculating avoided costs as appropriate, whether that be the DER ACC or alternative avoided cost methods where the DER ACC is not appropriate, as is the current case.

V. The NVBT Proposal Does Not Require the Investor-Owned Utilities to Compensate Unbundled Customers.

The Joint CCAs understand that each individual CCA is able to decide whether or not to participate in the NVBT and set their own tariff structure. Pacific Gas & Electric Company

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11 Pub. Util. Code Section 769.3(c)(5).
12 CCSA Opening Comments at 10.
13 AB 2316 Senate Floor Analysis, August 26, 2022.
14 Pub. Util. Code Section 769.3(c)(5).

("PG&E"), claims that if a particular CCA chose not to participate, and any of that CCA's generation customers were subscribed to an NVBT resource, the IOU, in addition to providing the transmission and distribution ("T&D") portion of the ACC value stack, would also have to either: (a) provide a generation credit to those CCA customers, or (b) provide compensation to the generator account for their resource without receiving any energy benefit to a subscribing customer.[15] This claim, however, contradicts the Joint CCA understanding of the proposal. If a CCA opts not to participate in the NVBT program, the Joint CCAs understand that CCA customers would be allowed to subscribe to NVBT projects and receive a bill credit from the IOUs for only the transmission and distribution portion of the ACC value stack.[16]

Therefore, the Joint CCAs believe the most likely and reasonable outcome is the third possible outcome raised by PG&E: that the generator is not credited for any energy or generation-related value as "the generation is not associated with any particular customer," and that "the NVBT resource, if seeking compensation for its energy, would presumably find another [off taker] or sell it into the [California Independent System Operator ("CAISO")] market as a merchant generator."[17] Thus, the Joint CCAs disagree with PG&E's overall assessment that this would be "extremely detrimental to bundled IOU customers,"[18] because there is no scenario where the IOU would have to compensate a CCA customer for a generation-related value. However, this discussion emphasizes the fact that treating these resources as in-front-of-the-meter, wherein a load serving entity ("LSE") could directly execute a contract for the resource,

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15 PG&E Opening Comments at 19.

16 *See* Exhibit CCSA-001 (Amended Prepared Direct Testimony of Robert Brandon Smithwood on behalf of the Coalition for Community Solar Access), Exhibit CCSA-007 (Surrebuttal Testimony of Robert Brandon Smithwood on behalf of the Coalition for Community Solar Access); *see also* PG&E Opening Comments at 18.

17 PG&E Opening Comments at 19.

18 *Id.*

would avoid this third outcome where the developer would have to find another off taker for the energy or sell it into the CAISO market as a merchant generator since the generation would be associated with the contracting LSE's customers.

VI. CONCLUSION

The Joint CCAs thank the Commission for its consideration of the matters set forth in these comments.

December 7, 2023

Respectfully Submitted,

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SUBMITTED 12/20/2023, 03:51 PM

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1. **Please provide your organization's feedback or any additional questions requesting clarification on the ISO's RA 101 overview of current showing mechanics, data inputs, and the CPM processes.**

Summary:

The California Community Choice Association (CalCCA) appreciates the opportunity to comment on the California Independent System Operator's (CAISO) December 6, 2023, RA Modeling and Program Design Working Group (WG).

The review and revision of the resource adequacy (RA) structure has become increasingly important. As the CAISO notes in its discussion paper, the types of resources, expectations of load, and programmatic changes of RA all have varying impacts on the ability to reliably serve customer needs. As the CAISO and stakeholders move forward in this WG and ultimately, a stakeholder process, the objectives of this effort and existing conditions on the grid should be made clear. This clarity should be provided by:

- Evaluating the efficacy of the available fleet through a probabilistic assessment and whether the stack-type analysis of the RA program will find the same outcome;
- Using data available to the CAISO such as RA showings, net qualifying capacity (NQC) listings, and historical import levels and trends to estimate future RA showings;
- Evaluating the ability of mechanisms to better incent resource availability in RA, such as unforced capacity (UCAP), consistently with Local Regulatory Authority (LRA) programs or proposals;
- Ensuring that LRA and CAISO rules are consistent and do not result in outcomes that are counter to LSE incentives;
- Providing the market with more transparency into the use and availability of RA resources for compliance purposes; and
- Encouraging the department of market monitoring (DMM) and other balancing authority areas (BAA) in the Western Electricity Coordinating Council (WECC) to coordinate to provide additional transparency of capacity conditions and expectations in the west.

*** **END OF SUMMARY** ***

1. CalCCA Response:

In response to a question from Southern California Edison Company regarding why the CAISO did not backstop for central procurement entity deficiencies, the CAISO responded, in part, that resources may not be available because load serving entities (LSE) may be holding resources to avoid Resource Adequacy Availability Incentive Mechanism (RAAIM) charges. However, RAAIM is a charge applicable to a Scheduling Coordinator for the generator, not an LSE. Only in the case that an LSE is a Scheduling Coordinator for generation would the potential holding of excess resources to avoid RAAIM be a potential issue. This is a narrow set of resources for which a local RA-eligible facility would be in the hands of a Scheduling Coordinator that is also an LSE, and the LSE has decided to hold the resource for potential RAAIM charges. Therefore, other causes (lack of incentive, locking in of a resource year-ahead (YA), showing a local resource for a system need, etc.) are more likely than RAAIM. This distinction is important because as market participants examine issues like this, the causes of the issue must be identified precisely so that changes can be made to make the RA process more effective and efficient. In this case, belief that the holding of RA capacity to serve RAAIM needs would suggest potential changes to mechanisms under the control of the CAISO. However, if the causes were elements like the lack of incentive, locking in of a resource YA, or the showing of a local resource to meet system need by an LSE, the changes to those mechanisms must occur at the LRA instead.

2. Please provide your feedback to the modeling discussion. The ISO is particularly interested in feedback on the current gaps or future objectives with modeling as it relates to the scope, models, methodology, assumptions, time frame, and suggestions on assumptions the ISO should make in the year ahead time frame (e.g., assessing if there is sufficient capacity if only 90% of system resources shown).

The CAISO Should Ensure Assumptions are Consistent with Local Regulatory Requirement Setting and Planning

The CAISO presented a modeling approach that looks at three time frames: year-ahead, 2-4 years forward, and 5-10 years forward. Each would use probabilistic modeling to ensure the assumed fleet meets a 1-in-10 loss of load expectation (LOLE) planning target. The CAISO's general approach and set of studies appear that they will offer valuable information about the sufficiency of the RA fleet to meet demand. It will be critical for the CAISO to use the same assumptions as the California Public Utilities Commission (CPUC) for use in their planning reserve margin (PRM) setting and integrated resource planning (IRP) to maximize the probability that RA showings will meet a 1-in-10 LOLE. To the extent the CAISO makes different assumptions than the CPUC, then the CAISO should make its assumptions public so LSEs know what they need to do to meet CPUC requirements and CAISO assessments.

The CAISO Should Issue Stack Analyses in addition to Probabilistic Modeling for Each Study Time frame

For transparency and ease of showing key drivers of the outcomes, the CAISO should use the same assumptions and data sources to conduct an RA Stack Analysis in each of the three time frames (YA, 2-4 years, 5-10 years) that parallels the probabilistic LOLE modeling. The stack should yield similar results, at least directionally, and any big differences will suggest the need for updating/refining the effective load carrying capability approach to ensure peak and net peak needs are satisfied. A stack is also more similar to how compliance is assessed, and it would be helpful to know if the supply stack expected to be available in those time horizons will satisfy LSEs compliance obligations.

Using only a probabilistic assessment for future RA periods (YA, 2–4 years, and 5–10 years in advance) will tell the CAISO whether the resource mix studied meets a probabilistic simulation of potential combinations of conditions over those future years. What it will not tell the CAISO, the LRAs, and stakeholders is whether the same fleet of resources that either passes or fails the probabilistic simulation would pass or fail an RA showing which is based on a stack type of process. If a set of resources fails the probabilistic simulation but passes a stack analysis, the conclusion is logically one of the following:

- An unlikely combination of inputs in a significant number of draws in the probabilistic simulation (a mathematically unlikely outcome);
- Resource counting that inaccurately predicts resource capacity for RA; or
- Inaccuracy of the PRM to account for ancillary services, forced outages, and load forecast error.

Unless the CAISO has identified a different manner to compare the results of its probabilistic modeling to the results of an RA showing, then evaluating these time frames on a stack basis (rooted in the showing requirements of the LRA) will be necessary to determine if the RA program will routinely produce a portfolio capable of meeting grid needs and capable of meeting RA showings compliance.

In the 2-4 and 5-10 year time frames, the comparison of probabilistic assessment and stack analysis will show whether there is a mismatch between methods. In the event that the probabilistic assessment predicts a reliable fleet but the stack analysis does not, then the IRP should evaluate the cause of the misalignment. Doing so will allow either; the IRP to account for these differences to produce a reliable fleet, or the RA program to consider changes to counting rules and PRMs to enable compliance under 1-in-10 conditions.

The CAISO Should Estimate a 100 Percent Annual Showing by using data and history already available to the CAISO

The CAISO explains that in its year-ahead RA sufficiency analysis, the CAISO will need to determine what resources to include in the analysis to get to a 100 percent shown capacity equivalent (because the year-ahead RA requirement is only 90 percent).

The CAISO asked if LSEs could provide additional information year-ahead about their expectations for their month-ahead (MA) showings to complete the 10 percent need. Doing so is both impractical and burdensome. In the current market conditions of scarce capacity, it is unlikely that LSEs know the availability of internal and import resources that could fill the remaining 10 percent. Without such knowledge, LSEs will be left to speculate without the benefit of knowing how much of the CAISO interconnected NQC is still available for procurement after the YA showing.

Instead, the CAISO has access to all LSE YA showings and supply plans. The CAISO also has the current NQC listing as well as knowledge of historical RA imports in the YA and MA time frame and the trend of those imports over time. Equipped with that knowledge, the CAISO is in the best position to use its available data to understand what is likely to be available to CA LSEs to meet the remaining MA RA requirement.

3. Please provide any feedback that was not already captured in response to the Problem Statement 2 (program design) and Problem Statement 3 (cost causation).

Problem Statement 2 should be updated to include UCAP as a sub-issue. UCAP is interrelated with RAAIM, the lack of a tool to incentivize performance, and rules for substitution and planned outages sub-issues. Including UCAP is likely to address many of the problems associated with these sub-issues. UCAP is also listed as a topic that will be explored in the upcoming RA proceeding at the CPUC (Rulemaking 23-10-011), and it will be important for the CAISO and CPUC to align on UCAP proposal development and implementation.

Problem Statement 3 should be updated to include proposed revision request 1280/credited resources as a sub-issue. The CAISO's tariff does not allow the CAISO to consider "credited" resources (resources count for RA under CPUC rules but are not shown on CAISO RA plans and supply plans) when allocating Capacity Procurement Mechanism (CPM) costs, a problem that while known of prior, became a reality after the CAISO's August 2023 CPM. In this circumstance, there were LSEs that had met their RA target when including the "credited resources" and LSEs that had not met their RA target even with their share of the "credited resources". However, when the CAISO performed its backstop and cost allocation, some of the previously compliant LSEs became short of RA once the CAISO had removed the "credited resources" from their showing. Thus, LSEs that had otherwise met their RA requirement were allocated a portion of the CAISO backstop cost that would not have been allocated to them if other LSEs would have met their compliance requirements. The CAISO should work with the CPUC to ensure credited resources' RA capacity is recognized, either through changes to the CPUC rules to have credit resources shown on supply plans or through a CAISO tariff change to support credited resources when allocating CPM costs.

4. Please provide your organization's feedback on current RA metrics published by the CAISO on CAISO's Today's Outlook, the Monthly Summer Performance Report, the Monthly Market Performance Report, or OASIS.

The Monthly Summer Performance Report's scope extends far beyond RA and includes detailed analysis that takes time to complete. The result is that the monthly RA showings' reports in the Monthly Summer Performance Reports are not always timely relative to the showing (e.g., it is December and the September 2023 monthly report is still not posted). The CAISO should consider separating out the RA portion of this report and posting it separately (e.g., on the Open Access Same-time Information System (OASIS)) so that it can be posted in a timelier manner. Timeliness of data should ensure that it is not posted too early so that it can be used to the detriment of the market (e.g., before the RA cure period concludes) but should also be posted soon thereafter so that the LRA can better assess market conditions that may have impacted LSEs ability to comply.

As discussed in question 2, the CAISO has access to information that would help the market determine the availability of capacity resources in California. The CAISO knows from supply plans the resources and quantities of RA committed to the CAISO. From the NQC list, the CAISO also knows all of the resources and quantities that are qualified to provide RA. The CAISO should publish aggregated information about the amount of resources available and the actual showings from those resources. The aggregation could be as simple as listing the amounts by technology (e.g., gas, wind, solar, hydro, etc.)

It has become increasingly difficult for LSEs to find available capacity resources. While this information will not provide a complete map to where capacity can be found, it can at least begin describing how much of the existing NQC list is being made available as RA.

In addition, the RA imports included in the reports do not include the pseudo-tie and dynamic transfers. Since the dynamic transfers are not in the NQC list posted to the CAISO site, it is difficult for third parties to use data in the reports to discern key information like what fraction of the eligible RA resources on the NQC list were shown. Earlier datasets posted by the CAISO include all RA imports (e.g., https://www.caiso.com/Documents/HistoricalResourceAdequacyImportAggregateData.xlsx). It would be helpful if CAISO reported aggregate RA imports from both specified and unspecified resources.

5. Please provide feedback to the DMM discussion of a sample of the RA metrics provided in the Annual Report.

The DMM should track actual capacity transaction prices rather than assume how hypothetical Combustion Turbine (CT) or combined cycle gas turbine (CCGT) earns the CAISO soft-offer cap, as the CAISO shows on slides 61 and 62. CalCCA's analysis of FERC Electric Quarterly Report (EQR) data shows that the weighted average price of capacity in California for the 12-months ending in September 2023 would add $101/ kilowatt (kW)-year to the revenue of a CT or CCGT, much higher than the $76-88/kW-year capacity revenue based on the CAISOs soft-offer cap. In fact, the weighted average price of capacity in the month of September 2023 was $13.2/kW-month which is 80-110 percent higher than the CAISO soft-offer cap. Individual transactions for capacity in September 2023 were above $60/kW-mo. Such high prices should be monitored and analyzed by the DMM.

Given the current market conditions for RA, it is imperative that the need for and availability of resources is examined more closely than it is today. In questions 2 and 4 of these comments, CalCCA has identified additional public information that should be made available. In addition, the DMM would be an ideal organization, due to its expertise in markets and independence, to examine and evaluate the cases in which CAISO interconnected NQC is not shown in an RA showing and the trend of import RA available to meet California LSE needs. Better still would be coordination between the DMM and other BAAs in the WECC to evaluate the complete set of resources, rules, and availability to better inform current RA needs as well as new resource build needs. A more complete analysis of the availability of RA resources is necessary to understand how best to ensure that resources are made available to meet grid needs.

6. Please provide any feedback not already captured.

CalCCA has no additional feedback at this time.

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

Order Instituting Rulemaking to Advance Demand Flexibility Through Electric Rates.	R.22-07-005

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON TRACK B WORKING GROUP REPORT

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SUMMARY OF RECOMMENDATIONS

- The California Public Utilities Commission (Commission) should adopt the recommendation of Pacific Gas and Electric Company (PG&E) through the Joint investor-owned utilities' Opening Comments to hire a neutral independent consultant to identify the obstacles and issues faced by community choice aggregators in obtaining timely hourly interval data from PG&E's ShareMyData platform; and

- The Commission should adopt the recommendation of The Public Advocates Office at the California Public Utilities Commission to convene a stakeholder process to address specifications regarding the price machine and price machine administrator

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Advance Demand Flexibility Through Electric Rates.	R.22-07-005

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON TRACK B WORKING GROUP REPORT

California Community Choice Association[1] (CalCCA) submits these reply comments in response to party Opening Comments on the *California Public Utilities Commission Demand Flexibility OIR Track B Working Group Report*[2] (Report), dated October 11, 2023.[3] The Opening Comments were filed in response to the *Assigned Commissioner's Phase 1 Scoping Memo and Ruling*[4] (Scoping Memo), dated November 2, 2022, and *Email Ruling Modifying Deadlines for Working Group Proposal and Comments,*[5] dated September 29, 2023.

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[1] California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Ava Community Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, Energy For Palmdale's Independent Choice, Lancaster 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] R.22-07-005, *Track B Working Group Report and Notice of Availability, Attachment A* (Oct. 11, 2023) (hereinafter referred to as the Report): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M520/K541/520541672.PDF.

[3] All references herein to party Opening Comments are to the Opening Comments filed in this Rulemaking (R.) 22-07-005, on or about November 13, 2023.

[4] R.22-07-005, *Assigned Commissioner's Phase 1 Scoping Memo and Ruling* (Nov. 2, 2022): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M498/K072/498072273.PDF.

[5] R.22-07-005, *Email Ruling Modifying Deadlines for Working Group Proposal and Comments* (Sept. 29, 2023): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M520/K520/520520661.PDF.

I. THE JOINT IOUS' RECOMMENDATION TO HIRE A NEUTRAL THIRD-PARTY EXPERT TO EXAMINE AND REPORT ON PG&E DATA ACCESS ISSUES SHOULD BE ADOPTED

As noted in CalCCA's Comments cited in the Report and in CalCCA's Opening Comments, the community choice aggregators (CCAs) do not agree with Pacific Gas and Electric Company's (PG&E's) characterization of the issues related to access to timely interval data through PG&E's ShareMyData (SMD) system as "isolated."[6] CalCCA recommended in Opening Comments that the California Public Utilities Commission (Commission) order a working group be formed to address the SMD issues. PG&E's recommendation in Opening Comments that a neutral consultant be retained to address the SMD issues is a reasonable alternative to efficiently identify and resolve the problems. As an initial matter, however, CalCCA responds below to an incorrect assertion in its Opening Comments regarding CCA responses to PG&E communications regarding SMD.

A. PG&E's Assertion That CCAs Failed to Respond Regarding ShareMyData Issues is in Error

The Joint investor-owned utilities' (Joint IOUs') assertion in Opening Comments that CCAs failed to respond to two recent emails from PG&E's SMD support team to clarify and solve open issues is in error, as confirmed by PG&E in emails with CalCCA.[7] The Joint IOUs state in response to concerns of stakeholders regarding PG&E's inability to provide timely interval data that:

> Recently, PG&E's ShareMyData support team reached out to CCAs on August 10, 2023 and again on October 10, 2023 to clarify and help solve open issues. Unfortunately, PG&E was not able to elicit any responses in those two instances.[8]

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6 *See* Report, at 182-183, 234-235, and 248; *see also* CalCCA Opening Comments, at 19-21.

7 *See* Joint IOU Opening Comments, at 23.

8 *Ibid.*

Based on the Joint IOUs' representation in Opening Comments, CalCCA followed up by email on November 16, 2023 with PG&E's counsel regarding the CCA recipients of the emails. The CCAs were unaware of the emails and concerned about PG&E's representation of a lack of a response. PG&E's counsel responded that upon further investigation within PG&E, emails from PG&E were responded to by representatives for Calpine Energy Services (Calpine), the billing agent of several of the CCAs. Calpine did respond to the emails through their main PG&E liaison for CCAs (and the Calpine response was forwarded by email to the ShareMyData team). Therefore, the representation that CCAs did not respond to PG&E regarding SMD issues is incorrect. As a matter of fact, the CCAs are very concerned about and responsive to PG&E regarding the SMD issues.

B. The Commission Should Adopt PG&E's Recommendation to Hire a Neutral Third-Party Expert

Given the impasse of the parties on identifying and solving the SMD issues, CalCCA agrees with PG&E's proposal to hire a neutral third-party expert to examine the problem from both the CCAs' and PG&E's perspective.[9] The report produced by the consultant identifying the SMD issues that need to be addressed should be provided to the Commission with recommendations of how to overcome these issues. As the SMD system is available to all customers and any improvements will benefit all customers, costs for the consultant should be paid by PG&E through distribution rates (i.e., collected from both unbundled and bundled customers). In addition, even while the neutral consultant works with the parties to identify and

[9] *Ibid* ("To facilitate better communication, PG&E proposes – with agreement of CCAs and external stakeholders – to hire a neutral third-party expert to examine the problem from both the CCAs and PG&E perspective. This consultant would produce a report that summarizes the challenges faced by CCAs in terms of data access with PG&E and would provide a clear picture of what the issues are that need to be addressed").

solve the SMD issues, the CCAs and PG&E should continue to work to resolve individual SMD issues as they occur (to the extent possible).

II. CAL ADVOCATES' RECOMMENDATION THAT THE COMMISSION REQUIRE A STAKEHOLDER PROCESS TO ESTABLISH REQUIREMENTS REGARDING THE PRICE MACHINE ADMINISTRATOR SHOULD BE ADOPTED

The Commission should adopt the recommendation of The Public Advocates Office at the California Public Utilities Commission (Cal Advocates) to establish a stakeholder process regarding the Price Machine.[10] As noted in Cal Advocates' Opening Comments, the Staff Report on the Price Machine noted that the Price Machine Administrator (PMA) can be elected by the Commission or determined through a stakeholder process.[11] CalCCA agrees with Cal Advocates that given the novelty of the price machine, stakeholders should have the opportunity to weigh in on the identity of the PMA, and the scope, parameters, deliverables, timeline, and fixed and recurring costs of the price machine.

III. CONCLUSION

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

Respectfully submitted,

Evelyn Kahl

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

December 22, 2023

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10 Cal Advocates' Opening Comments, at 6.
11 *Id.*, at 6 (citing the Report, at 213).