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 2025 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U39E)	Application 24-05-009

RESPONSE TO ALJ RULING OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION

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SUBJECT MATTER INDEX

SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

- The high Resource Adequacy (RA) Market Price Benchmark (MPB) reflects facts the Commission knows well – System RA capacity is scarce, and the market price of such capacity has increased sharply within the past several years. Timely setting rates that incorporate this market characteristic is the best way to avoid under- or over-collections; failing to do so likely will exacerbate future under- or over-collections and the resulting rate changes, rather than providing permanent rate relief.
- While the market value of RA may change on account of the slice of day (SOD) framework, there is no consensus on what the change will be, whether it warrants a revision to the RA MPB methodology, and whether any revision to the MPB methodology will increase or decrease the likelihood of over- or under-collections.
- No special procedural or substantive considerations are necessary in this proceeding since, after taking into account the 2024 MPBs, bundled customer generation rates in PG&E and SCE's service territories *decrease* compared to March 2024 rates; and rates in SDG&E's service territory increase within the range of prior Commission-approved rate increases. Incorporating actual results from lower market prices experienced during 2024 should also reduce pressure on bundled customer rates. The October Update may change these conclusions, but there are sufficient procedural opportunities to address that possibility at a later date without delaying the proceeding's resolution.
- The Commission should continue to preclude the consideration of revisions to the RA MPB methodology that PG&E and SDG&E have disguised as ratepayer mitigation measures.

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RESPONSE TO ALJ RULING OF CALIORNIA COMMUNITY CHOICE ASSOCIATION

Pursuant to ALJ Fox's October 8, 2024, E-Mail Ruling Requesting Party Comments on Procedural Mechanisms (ALJ Ruling) and the August 1, 2024, *Assigned Commissioner's Scoping Memo and Ruling*,[1] California Community Choice Association[2] (CalCCA) hereby submits these Comments in response to the ALJ Ruling with regard to the *Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2025 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U39E)*, submitted May 15,

[1] Application ("A.") 24-05-009, *Email Ruling Requesting Party Comments on Procedural Mechanisms* (Oct. 8, 2024) (ALJ Ruling); A.24-05-009 *Assigned Commissioner's Scoping Memo and Ruling* (Aug. 1, 2024) (Scoping Ruling).

[2] 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 of Southern California, 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.

2024 (Application).[3] CalCCA appreciates the opportunity to provide comments on whether additional steps—within the current scope of this proceeding—should be taken with regard to the recently published Resource Adequacy (RA) Market Price Benchmark (MPB). CalCCA and the Joint CCAs (San Diego Community Power and Clean Energy Alliance) are providing nearly identical comments on this issue across all three utilities' Energy Resource Recovery Account (ERRA) forecast proceedings.

Whether additional procedural or substantive steps should be taken to address the RA MPB should not hinge on whether the RA MPB substantially alters the final value of one of the inputs to customers' generation and Power Charge Indifference Adjustment (PCIA) rates — the value of the utilities' capacity portfolios in 2024 or the forecasted value of those portfolios in 2025. It should hinge, instead, on a fulsome evaluation of the final rates customers will pay. The release of the relatively high RA MPBs and their effects on the calculation may leave the impression that the sky is falling; it is not. The RA MPBs have a material effect on rates, but other factors, such as the change in the Energy Index, mute the direct impact on ratepayers. In addition, the RA and Renewable Portfolio Standard (RPS) MPBs are doing precisely what the Commission intended: accurately valuing the investor-owned utility (IOU) PCIA portfolios based on current market conditions and, therefore, preventing cost shifts among customers. The analysis in these comments shows the resulting rates do not warrant special procedural or substantive mechanisms at this time, although the upcoming October Update may change the nature of potential rate increases.

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[3] A.24-05-009, *Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2025 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U39E)*, (May 15, 2024).

First, this year's RA MPB does not change the likelihood of over- or under-collections on its own. The high system RA MPB reflects facts the Commission knows well—System RA capacity is scarce, and the market price of such capacity has increased sharply within the past several years. Since Decision (D.) 18-10-019, the Commission's "forecast and true-up" framework for setting both bundled generation rates and PCIA rates has created large over- and under-collections when the price for energy, capacity, or renewable energy credits (RECs) shifts from one year to the next. Using this year's RA MPBs (both the 2024 Actual RA MPB and 2025 Forecast RA MPB) to set bundled generation and PCIA rates is not an anomaly within that framework; it is an intentional feature of that framework meant to reflect changes in market value and ensure ratepayer indifference.

Failing to recognize the higher System RA prices within the market today could only exacerbate future under- or over-collections, and rate changes, if market prices continue to rise. Therefore, without a change to the RA MPB methodology this year—an issue the ALJ Ruling recognizes is out of scope in this proceeding—the potential for an over- or under-collection is as likely as it is each year and does not warrant special procedural considerations on its own.

The three IOUs have suggested new market forces, such as the Commission's Slice of Day (SOD) framework, change the value of RA. However, the IOUs do not yet agree on the changes that should be made to the RA MPB. Southern California Edison Company (SCE) suggests changes to how to quantify the RA to which the MPB should be applied, and Pacific Gas and Electric Company (PG&E) suggests the RA MPB itself needs to change. While the market value of RA may change on account of the SOD framework, there is no consensus on (1) what the change will be, (2) whether it warrants a revision to the RA MPB methodology, or (3) whether any revision to the MPB methodology will increase or decrease the value of the IOUs' capacity portfolios relative to the *status quo*. As a result, neither parties nor the Commission can accurately predict at this time whether new market forces, and any resulting change to the RA MPB on account of those market forces, will increase or decrease the likelihood of over- or under-collections. Predictions about the likelihood of an over- or under-collection on account of SOD, or other market changes, in response to the ALJ Ruling should therefore be given little weight.

Second, and most importantly, bundled customer rates in PG&E's and SCE's service territories are projected to *decrease* compared to the bundled customer rates in place when the ERRA Forecast applications were filed. The rates in San Diego Gas & Electric Company's (SDG&E) service territory are projected to increase within the range of rate changes adopted in recent ERRA forecast cases, such as PG&E's 2022 ERRA Forecast case. SDG&E's situation should improve as more actuals are realized. With the soft brown power prices currently in the market, on-going updates to 2024 Portfolio Allocation Balancing Account (PABA) and ERRA balances (*i.e.*, including actual costs and revenues for 2024) should improve the situation for bundled customers rather than make them worse.

Therefore, at this time, the Commission need not adopt the type of special true-ups or amortization periods it has adopted as a last resort in previous ERRA forecast and ERRA trigger cases. If the October Update results in forecasted generation rates that fall outside of these norms, the Commission can still temper any drastic rate increases—for either bundled or unbundled customers—using such tools as a last resort. The procedural schedule in each proceeding still allows multiple opportunities to make those proposals in the form of the October Updates themselves and in comments responsive to those testimonies.

Lastly, the ALJ Ruling prohibits proposals that will modify the existing methodology for calculating the RA MPB, stating they are out of scope in this proceeding. As such, proposals provided in response to the ALJ Ruling that are disguised as ratepayer mitigation measures but in effect modify the RA MPB—such as PG&E's previous proposal to cap the RA MPB which was already rejected as out of scope—continue to be out of the scope of this case and should not be revived or considered. Adopting such measures will not comport with the Commission's existing indifference framework and, therefore, will violate State law prohibiting cost shifts between bundled and unbundled customers.

I. THE RA MPB DOES NOT CHANGE THE LIKELIHOOD OF AN OVER- OR UNDER-COLLECTION UNDER THE COMMISSION'S CURRENT METHODOLOGY.

Before turning to the enumerated questions in the ALJ Ruling, the Commission poses a threshold question, asking: "Should this proceeding consider approaches to ensure that there is not an over-collection or under-collection for the applicant as a result of the existing MPB calculation methodology?"[4] In response, CalCCA respectfully urges the Commission to refrain from adding any additional process to this proceeding because ERRA forecast proceedings are already structured to address applicant over- or under-collections. This is because the RA MPB was purposely designed to reflect the on-the-ground realities of the RA marketplace, and because the impacts on the RA MPB from any future, *potential* changes to the calculation methodology are far from known. Timely setting rates that recognize capacity is valuable under the Commission's current PCIA framework is the best way to avoid under- or over-collections.

A. The RA MPB is Operating as the Commission Intended -- Mitigating Over- and Under-Collections by Reflecting the Reality of High Capacity Prices in the Market.

The Commission made fundamental changes to the PCIA framework in D.18-10-019. Prior to D.18-10-019, the PCIA rate was set only on a forecast basis with no after-the-fact true-up for

[4] ALJ Ruling at 3.

unbundled customers. D.18-10-019 approved a true-up for the PCIA using actual record net costs for the PCIA eligible resources and billed revenues from both bundled and departing load customers. These changes created the current ratesetting structure that relies on actual, recent transactions in the California market to ensure customer indifference using a two-pronged approach: (1) a forecast of the Indifference Amount, and (2) a true-up of the forecast via the year-end PABA balance. The true-up occurs via the IOUs' PABAs, which are a rolling true-up between the forecasted costs and revenues used to determine the Indifference Amount and the actual costs and revenues an IOU realizes during the year. Thus, the very nature of this proceeding and the framework it follows is meant to address an over- or under-collection for the applicant and mitigate an over- or under-collection in the following year.

In both the forecast and the true-up, the capacity and other attributes the IOUs retain are assigned an imputed value based on the RA MPB that relies on real-world transactional data. When forecasting the Indifference Amount, Energy Division calculates the forecast RA MPB according to *actual*, *already executed* RA transactions. As Energy Division explained, the Forecast RA Adders for system and flexible RA are calculated using the volume-weighted average value of all RA-only market transactions from September 2023 through August of 2024 (for delivery in 2025).[5] And the forecast RA Adder for Local RA are determined in a similar manner.[6] In other words, the forecasted portion of the PCIA framework reflect the actual market prices participants are paying in the market.

To calculate the year-end PABA balance, the final RA Adders for system and flexible RA are calculated using the volume-weighted average of all IOU, CCA, and electric service provider

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5 A.24-05-007, A.24-05-009, A.24-05-010, Energy Division, *Market Price Benchmark Calculations* (October 4, 2024) (October 4, 2024, MPB Calculations).

6 *See* October 4, 2024, MPB Calculations.

(ESP) RA-only market transactions executed from December of 2022 through August of 2024, for delivery in 2024.[7] The final RA Adder for Local RA is determined in a similar manner.[8] Thus, the true-up portion of the PCIA framework also reflects the actual market prices participants are paying in the market.

Of course, the nature of a forecast as complex as the forecasted Indifference Amount is that—like any good model—it will always be ultimately inaccurate as a forecast. The current PCIA framework, therefore, has created an under- or over-collection in the PABA balance every year on account of changes in the cost, value and volume of RA, RECs, and energy. Some of these under- and over-collections have been quite large, such as SCE's forecast in 2021 for a year-end PABA under collection of almost $500 million.[9] If the newly Forecast RA MPBs result in a large under- or over-collection for next year, it will merely be another entry in a history of large swings in revenue requirements since D.18-10-019.

Many times, including this year, the swings in the forecasts counteract each other. While the RA MPBs are high this year, declines in the Energy Index offset those increases and mitigate resulting rate increases, as discussed further below. In other words, the RA MPB—or any other MPB in isolation—does not drive under- or over-collections the following year. Rather, it is the year-to-year *change* in those indices, and their interaction with each other, that can drive an under- or over-collection (and which under- or over-collection is ultimately addressed by the true-up).

The high RA MPBs Energy Division forecasts for 2025 illustrate the market conditions CCAs and the IOUs have navigated in recent years. The parties to this proceeding largely agree

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7 October 4, 2024, MPB Calculations.

8 *See id*.

9 D.20-12-035 at 27.

there is scarcity in the RA market, which is an issue CalCCA and its member CCAs have attempted to tackle repeatedly and in earnest in other proceedings. The RA scarcity has driven a substantial increase in the market value of System RA. For example, PG&E's application points to market scarcity to justify its proposal to cap the RA MPB.[10] SDG&E's Application recognizes that prices for RECs and RA are significantly higher than the 2024 benchmarks.[11] With this unified market experience, it is no surprise that the forecasted RA MPB is elevated. The RA MPBs are calculated using real market data, just as the Commission ordered in D.18-10-019.[12]

The elevated level of this year's MPBs is a not a flaw in the Commission's approved PCIA framework. Rather, it is an intentional feature of that framework meant to reflect changes in market value and ensure ratepayer indifference. In other words, the RA MPB is operating as the Commission intended. Unless the Commission adopts a change to the RA MPB methodology—an issue the ALJ Ruling recognizes is out of scope in this proceeding—the potential for an over- or under-collection is as likely this year as it is each year. As such, special procedural considerations are not warranted.

B. Modifications to the RA MPB Calculation Methodology May Not be Necessary as it is Unclear Whether Such a Change Will Change the Potential for Under- or Over-Collections.

All three IOUs have argued to some degree that the calculation of the RA portfolio value should change on account of the Commission's new SOD framework. However, the IOUs do not agree on what those changes should be. SDG&E stated at its Prehearing Conference that the

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10 A.24-05-009, *Pacific Gas and Electric Company Prepared Testimony*, at 2-13:19-21 (May 15, 2024) (PG&E Prepared Testimony).

11 Application at 12.

12 *See* October 4, 2024, MPB Calculations; *see also* D.18-10-019 at Appendix 1.

calculation of the RA MPB should change on account of SOD,[13] but then excluded any such proposal in its testimony. SDG&E stated that "no changes to the PCIA RA methodology for SOD have been discussed in front of the Commission, and therefore no changes have been approved."[14] PG&E has stated the methodology for calculating the RA MPB may no longer fairly value RA when it is used for IOU compliance and PCIA ratemaking purposes due to SOD and other market factors. PG&E therefore proposed an RA MPB cap.[15] SCE's supplemental testimony proposes to change how it calculates the quantity of RA capacity in its portfolio using an "SOD RA Effectiveness Factor."[16] In sum, one IOU proposes to adjust RA quantity (SCE), one believes the RA price will need to be adjusted and recommends further review (PG&E), and one says it is waiting for Commission approval to change the PCIA methodology (SDG&E).

It is possible SOD will change how the RA market operates and require a change in how the PCIA methodology values the utilities' RA portfolios. However, as both PG&E and SDG&E have observed, "it is not yet known what the full impact [of SOD] on the RA market will be and associated RA MPBs."[17] There is insufficient data available to know what changes may be required to the RA Adder MPB or the quantity applied to the MPB. For example, SCE indicated in discovery that it has not yet developed an hourly RA price curve for 2025, but may potentially develop one for future years pending developments of SOD implementation.[18] The final answer to the question of the impacts of SOD on the PCIA framework may be a combination of modifications

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13 A.24-05-010, Transcript (Tr.) Vol. 1 at 13:7-25-14:8-17 (Jul. 12, 2024).

14 A.24-05-010, Exh. SDGE-05 at SM-6:3-9.

15 PG&E Prepared Testimony at 2-13:19-21.

16 A.24-05-007, Exh. SCE-04 at 8:9-11:4.

17 PG&E Prepared Testimony at page 2-14:18 to 2-15:3; A.24-05-010, Exh. SDGE-02 at JE-6:5-9 (discussing uncertainty surrounding the impact SOD will have on RA).

18 A.24-05-007, Exh. CCA-01 at 21:2-6 (citing to SCE response to CalCCA 6.08).

to how to forecast the RA quantity and price. To reach that final answer, the Commission, the three IOUs, and other interested parties including CalCCA should conduct further analysis before reaching a conclusion on what such changes will be and how they will impact the current value of the IOUs' portfolios.[19] Thus, it is unclear whether SOD, or any other market change, warrants (1) modifications to the Commission's MPB calculation, (2) what those changes will be, and (3) whether those changes will increase or decrease the likelihood of over- or under-collections.

C. Timely Setting Rates that Recognize Capacity is Valuable is the Best Way to Avoid Under- or Over-Collections.

The Commission's current framework ensures indifference for all customers by comparing the value of the IOUs' portfolio to their costs. Ignoring the high RA capacity prices in the market today, and the resulting high value of the IOUs' RA capacity portfolios—will intentionally build an under-collection into next year's rates. If RA prices remain the same, or especially if they continue to rise, that under-collection could worsen, which could exacerbate the risk of future rate volatility and/or a sharp rate increases for bundled customers. As such, unless and until the Commission changes the MPB methodology, the best way to minimize under- or over-collection is to apply the MPBs produced by the existing methodology and rely on the PABA and ERRA balancing accounts to set rates for 2025.

II. AT THIS TIME, THE RA MPB DOES NOT WARRANT CHANGES TO THE RATEMAKING PROCESS WITHIN THIS PROCEEDING.

A. Question 1: Do You Expect the Released RA MPB to Have a Significant Impact on the Issues Scoped Into This Proceeding?

The change in the RA MPB alters the final value of the IOUs' capacity portfolios in the 2024 year-end balances and the forecasted value of those portfolios in the 2025 Indifference

19 A.24-05-007, Exh. CCA-01 at 13:10-13.

Amount. However, the ultimate purpose of this proceeding is to set generation rates for 2025, and the Commission's ratemaking principles focus on how a proceeding will change rates compared to the rates customers currently pay.[20] While further analysis remains to be done, RA MPB may not have a major impact on rates, as compared to the rates in place when the Application was filed, after changes to the other benchmarks are taken into account.

Neither parties nor the Commission will fully know the impacts to rates until each IOU files its October Update. However, CalCCA analyzed the impact of the newly released MPBs on PCIA and bundled generation rates using the IOUs' workpapers provided with their initial Applications. The CalCCA analysis makes the following assumptions:

- Updating the 2024 and 2025 MPBs, but not updating the corresponding volumes to which those MPB are applied, *i.e.*, generation, RECs, RA, and net qualifying capacity;
- Updating PCIA and bundled generation rates to reflect the lower 2025 energy prices, higher RPS MPB and higher RA MPB;
- Updating the 2024 PABA and ERRA year-end balances included in PCIA rates to reflect the final 2024 RA and RPS MPBs (2024 PABA and ERRA year-end balances were not updated for changes in actual 2024 energy market prices beyond those in the initial applications);
- Excluding changes to which the IOUs and parties have agreed to make since the initial applications, *i.e.*, those changes to which the IOUs agreed in rebuttal testimony, via data request responses issues in lieu of cross examination, or, in SCE's case, via amended rebuttal testimony;[21]

Based on these assumptions, the current projected changes to rates in each utility's service territory are summarized in Table 1 below.

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[20] *See* D.23-04-040; Pub. Util. Code § 454(a) (explaining that the Commission will not allow a new rate unless it determines that the new *rate* is justified).

[21] The impacts to SCE's rates are calculated using the model in their August 19, 2024, Supplemental Testimony where the utility introduce changes tied to SOD; the rate impacts calculated herein do not include changes SCE adopted in amended rebuttal testimony.

Table 1:

PG&E	PCIA Vin 2009-2020	PCIA Vin 2021-2023	PCIA Vin 2024	Gen	Gen % Change vs. March
March 1, 2024	0.0098	0.0012	0.0077	0.1689	
Filed	0.0240	0.0165	(0.0020)	0.1422	-16%
MPB Update	0.0067	(0.0174)	(0.0045)	0.1593	-6%

SCE	PCIA Vin 2009-2020	PCIA Vin 2021-2023	PCIA Vin 2024	Gen	Gen % Change vs. March
March 1, 2024	(0.0053)	(0.0069)	(0.0030)	0.1278	
Filed	0.0116	0.0152	(0.0138)	0.1017	-20%
MPB Update	(0.0097)	(0.0269)	(0.0343)	0.1067	-17%

SDG&E	PCIA Vin 2009-2020	PCIA Vin 2021-2023	PCIA Vin 2024	Gen	Gen % Change vs. March
March 1, 2024	0.0056	0.0151	0.0068	0.1502	
Filed	0.0085	0.0125	0.0068	0.1353	-10%
MPB Update	0.0042	0.0028	0.0410	0.1935	29%

There are a number of key takeaways from Table 1. First, the impacts to rates within each service territory are varied. If a new procedural or substantive approach is adopted by the Commission, the impacts of an identical approach in each IOU service territory will have varied results. Second, in PG&E and SCE's service territory, bundled rates will actually *decrease* compared to the rates in place when their respective Applications were filed. In PG&E's service territory, bundled rates will decrease nearly \$0.01/kWh, from \$0.1689/kWh to \$0.1593/kWh, which is a *six percent decrease* in rates. In SCE's service territory, bundled rates will decrease over \$0.02/kWh, from \$0.1278/kWh to \$0.1067/kWh, which is a *seventeen percent decrease* in rates.[22] Third, the largest increase in rates from commodity rates for bundled customers is about 4.3 cents, or 29 percent, in SDG&E's service territory.[23] Although the increase is significant, the Commission has adopted similar increases before. For example, in PG&E's 2022 ERRA Forecast case, the Commission approved a bundled customer generation rate increase of 32.6 percent.[24] That same year, the Commission also adopted an increase in commodity rates in SDG&E's ERRA Forecast proceeding of 19 percent, and an increase of 23 percent in SCE's ERRA Forecast proceeding.[25] Thus, the current forecasted increase in SDG&E's bundled rates is within the range of rate increases the Commission has deemed acceptable in prior years.

Lastly, with the soft brown power prices currently in the market, on-going updates to 2024 PABA and ERRA balances, *i.e.*, including actual costs and revenues since the utilities' initial applications, may improve the situation for bundled customers rather than make them worse. The result is that the rate changes are within the range of changes the Commission has adopted previously compared to rates in place at the time the Applications were filed. In fact, forecast bundled customer rates may decrease further as January 1, 2025, approaches and more actuals are included in the revenue requirement.

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22 While SCE implemented an ERRA Trigger rate change on October 1, 2024, that substantially decreased bundled customer rates (see SCE AL 5371-E), that decrease essentially acts as an early implementation of the year-end brown power true-up (the Energy Index true-up) for bundled customers. For that reason, Table 1 compares the rates in SCE's filing to the rates in the utility's original application.

23 SDG&E AL 4495-E, *Notice of ERRA Trigger in Compliance with Decision 07-05-008* (notifying the Commission that its ERRA balance was in a triggered position, but requesting acknowledgment that no other action was needed at that time); SDG&E AL 4495-E-A, *Partial Supplemental – Notice of ERRA Trigger in Compliance with Decision 07-05-008* (Sept. 20, 2024) (notifying the Commission that its ERRA balance was no longer in a triggered position).

24 *See generally* D.22-02-002 (Feb. 11, 2022).

25 D.21-12-040; *see* Revised Updated Direct Testimony at GM-9 (Nov. 15, 2021) (illustrating current and proposed bundled generation rates); D.22-01-003; *see* A.21-06-003, *SCE Errata to the Updated Testimony: Energy Resource Recovery Account (ERRA) 2022 Forecast of Operations*, p. 138 (Nov. 9, 2021) (illustrating current and proposed bundled generation rates).

B. Question 2: Should The Commission Consider Procedural Options For Addressing Any Impacts Within The Timeline Of This Case? If So, How? For Example, Should A Ruling Be Issued Seeking Comment On Options For How To Address The Impact, And/Or, Should Parties Address These Options In Their October Update Filings And Comments?

The Commission should not consider additional procedural options at this time to address impacts of the RA MPB on the issues in scope in the ERRA Forecast proceedings. First, as these comments explain in response to Question 1 above, the RA MPBs likely do not impact the scoping issues in a manner that require the Commission's intervention. Based on the information currently available, as a result of the new MPBs rates will either change in bundled customers' favor or will change in a reasonable manner based on past ERRA Forecast cases.

Second, should the October Update reveal more dramatic increases in bundled customer rates due to the RA MPB, the scoping ruling in each proceeding gives parties multiple opportunities to address these impacts without requiring additional procedural options. Depending on the ERRA Forecast proceeding, parties have between two or three more pleadings to address those impacts (*i.e.*, the October Update, and comments responsive to the October Update, in addition to comments on the Proposed Decision). In sum, there is plenty of opportunity to address any rate impacts without the Commission creating special procedural (or substantive) options. If the Commission creates additional process to address any impacts from the RA MPB, it will unnecessarily squeeze an already-expedited case at a time when parties are working to develop October Update testimony, analyze and issue discovery on that testimony, and comment on that testimony.

C. Question 3: If Impacts and Procedural Options Exist, Are There Ways to Address Impacts of the RA MPB Within the Timeline of This Proceeding? For Example, Should the Commission Consider an Early True-Up Via Advice Letter Process or Another Option?

1. Options to address the RA MPB that are within the scope of this proceeding are not necessary at this time.

As these comments explain in response to Questions 1 and 2 above, the extent to which the final RA MPB will impact bundled customer generation rates is not yet clear, and therefore the Commission need not consider additional procedural options to address those impacts at this stage. While there are ways to address the impacts of the RA MPB on bundled customer generation rates within the timeline and scope of this proceeding, those approaches do not need to be considered at this time. The forecast Bundled customer generation rates will either decrease or increase within the bounds of prior rate increases the Commission has approved.

For example, one option the Commission has considered is to amortize a revenue requirement over more than 12 months to reduce the immediate impact of that revenue requirement on customers' rates. The Commission adopted this approach when addressing the fallout from the PCIA cap, and the above-cap portion of the PCIA revenue requirement was amortized via the PCIA Undercollection Balancing Account in rates for 2021, 2022 and 2023.[26] The Commission has also exercised different amortization periods as a result of bundled customer rate increases due to ERRA trigger proceedings.[27]

However, amortizing revenue requirement increases can exacerbate rather than temper rate volatility over the long term. Amortization is not a permanent rate relief strategy, but is rather

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[26] D.20-12-038 at 18-19 (adopting a three-year amortization period for PG&E's 2020 PUBA amount); D.20-07-002 at 53-54 (adopting a similar amortization for SCE's 2020 PUBA year-end balance).

[27] *See e.g.*, D.20-12-028 at OP 1 (granting three-year trigger balance amortization); D.24-08-015 at 16 (granting one-year trigger balance amortization).

simply a delay of an inevitable rate increase. The Commission should note that 2025 forecasted rates may in fact be the right time to *recover* increased bundled customer rates on account of the RA MPB. While the market values of RA capacity and RECs are high today, declining brown power prices, especially those South of Path 15, substantially offset the impacts and mute the effect of those benchmarks on PCIA and bundled customer rates. There is no obvious reason to believe future conditions will be *more* favorable to recovering RA and REC costs.

Special rate treatment should only be used as a last resort to address extreme rate increases, and those conditions do not currently exist. If the October Update reveals circumstances in the market that create the right conditions to amortize certain revenue requirements, however, it is important to provide rate relief to customers that will realize a decrease in rates as soon as possible. For example, should the Commission take this "last resort" option of increasing the amortization period for a bundled customer revenue requirement in order to avoid rate shock, it should not simultaneously delay the implementation of correspondingly *lower* PCIA rates.

In addition, it is unlikely an "early true-up" via the Advice Letter process will have an impact on final rates. The true-up involves resolving the differences between 2024 forecasted costs and revenues and the actual costs and revenues the utility realizes in 2024. It therefore requires the utility to know the actual costs and revenues it has realized in a given month to record those values to the applicable balancing accounts. The true-up occurs for a given month in the following month after the accounting close for the given month. It is not possible to have the *actual* values necessary to conduct a true-up earlier than those actual values are available. Under the Commission's current framework for setting final generation rates, all months will be trued up by January 1, 2025, except for December 2024. The October Update includes actuals through September, while the November 15 Tier 2 and the December 31 Tier 1 Advice Letters that make up each utility's consolidated rate change include actuals for October and November, respectively.[28] Thus, actuals are included when setting rates for 2025 as soon as practicable after they become available. Therefore, an earlier true-up within the timeframe of this proceeding is both not possible until after each month's accounting close and is unlikely to have an impact on rates for which the existing process does not already account.

2. Proposals to modify how the PCIA revenue requirement is calculated go beyond the scope of this proceeding and should not be considered in response to the ALJ Ruling.

The ALJ Ruling warns that comments in response to the ruling "should be limited to the scope of this proceeding, and not address issues outside of the scope, such as whether the MPB methodology should be changed."[29] Therefore, any change to the MPB methodology, including any artificial cap on the MPB similar to proposals in SDG&E and PG&E's Applications,[30] is beyond the scope of this proceeding and beyond the scope of the ALJ Ruling. If PG&E, SDG&E or SCE propose a similar measure in response to the ALJ Ruling, the Commission should reject it.

In its Application, PG&E conditionally proposed an improper modification to the PCIA ratemaking framework, and SDG&E stated it may propose something similar in its October Update. Scoping Rulings in both cases denied consideration of those proposals.[31] The Commission should maintain this prohibition and prevent any attempt to disguise as ratepayer mitigation measures these fundamental changes to setting the PCIA revenue requirement.

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[28] Resolution E-5217 at 13.

[29] ALJ Ruling.

[30] SDG&E Application at 12; A.24-05-010, Exh. SDGE-05; *see also* PG&E Prepared Testimony at Chapter 2.

[31] A.24-05-010, *Assigned Commissioner's Scoping Memo and Ruling*, p. 5 (Aug. 14, 2024); A.24-05-009, *Assigned Commissioner's Scoping Memo and Ruling*, p. 3 (Aug. 1, 2024).

PG&E's original proposal can be summarized as follows. On account of the 2024 Final ($28.65/kW-mo) and 2025 Forecast ($42.54/kW-mo) System RA MPBs exceeding the 2024 Forecast System RA MPB ($15.23/kW-mo), PG&E therefore would have asked the Commission to ignore the 2024 Final and 2025 Forecast System RA MPBs, and instead continue to apply the lower 2024 Forecast System RA MPB for PCIA ratemaking purposes.[32] Further, PG&E would have asked the Commission to keep the RA MPB artificially capped at the 2024 Forecast level ($15.23/kW-mo) until some indefinite point in the future when the Commission completes an examination of the RA MPB and RA market in a docket PG&E does not identify.[33] PG&E would have tracked the difference in the value of the RA attributes transferred between PABA and ERRA using the artificially frozen RA MPB and the actual RA MPBs (and ultimately, at some point in the future, impose the accumulated balance on its customers).[34]

While PG&E's application characterizes its proposal as a mere "mitigation measure,"[35] it goes far beyond that. PG&E's proposal would have added a major new component – an RA value cap – to the PCIA ratemaking framework as modified by D.18-10-019 and D.19-10-001. Nothing in those decisions, or in any subsequent Commission decisions, authorizes an RA value cap (or any similar "mitigation measure"). On the contrary, the PCIA framework *requires* the IOUs to use the 2025 Forecast RA MPB[36] to determine its Indifference Amount.[37] The framework also *requires* PG&E to use the 2024 Final RA MPB to determine its 2024 year-end balance in the PABA.[38]

32 PG&E Prepared Testimony at 2-18.

33 *Id.* at 2-19.

34 *Id.* at 2-18.

35 *Id.* at 2-2:4.

36 *See* D.19-10-001 at 27.

37 D.19-10-001, Attachment B at 1 (Table II).

38 *Id.* at 2 (Table IV).

Until and unless the Commission undertakes a review of the RA MPB methodology, and makes the determination that it needs to be modified, the IOUs must comply with *existing* Commission decisions, including D.18-10-019 and D.19-10-001. These decisions require the IOUs to use the 2025 Forecast RA MPBs to determine their Indifference Amounts and require PG&E to use the 2024 Final RA MPBs to determine its 2024 year-end balance in the PABA. The IOUs cannot deviate from these approaches to disguise as "mitigation measures" fundamental changes to calculating revenue requirements.

Indeed, doing so would violate State law. Section 365.2 of the California Public Utilities Code mandates indifference for departed customers, requiring the Commission to "ensure that departing load does not experience any cost increases as a result of the allocation of costs that were not incurred on behalf of the departing load."[39] Under Section 366.2, unbundled customers are responsible solely for "estimated net unavoidable electricity costs" when determining indifference, and those costs must be reduced by the benefits in the IOUs' portfolios that accrue to bundled customers.[40] Decisions 18-10-019 and 19-10-001 apply the mandates in Sections 365.2 and 366.2 and create the PCIA framework to maintain indifference.

Any deviation from the existing PCIA framework—such as capping RA value as PG&E proposed—will result in impermissible cost shifts to departed customers. In other words, PG&E's proposal will require departed load customers to indefinitely subsidize bundled customer rates if RA prices go up, while PG&E relies on the existing PCIA resource portfolio to meet its own RA requirements for bundled customers. PG&E's RA cap proposal was not about mitigating rate volatility, but rather was an attempt to lower bundled customer generation rates by shifting costs

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39 Cal. Pub. Util. Code § 365.2.

40 Cal. Pub. Util. Code § 366.2 (f)(2), (g).

to departed load. To the extent any utility advances a similar proposal in response to the ALJ Ruling, the Commission should disregard and reject that proposal.

III. CONCLUSION

For the foregoing reasons, CalCCA urges the Commission to refrain from taking special steps—procedural or otherwise—in response to the RA MPB at this time.

Respectfully submitted,

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October 14, 2024

Counsel to CALIFORNIA COMMUNITY CHOICE ASSOCIATION

STATE OF CALIFORNIA
CALIFORNIA ENERGY COMMISSION

IN THE MATTER OF: *2024 Integrated Energy Policy Report Update (2024 IEPR Update)*	DOCKET NO. 24-IEPR-03 RE: Forecast in Electricity System Planning Workshop of Wednesday, October 2, 2024

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE FORECAST IN ELECTRICITY SYSTEM PLANNING WORKSHOP

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October 16, 2024

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STATE OF CALIFORNIA
CALIFORNIA ENERGY COMMISSION

IN THE MATTER OF: *2024 Integrated Energy Policy Report Update (2024 IEPR Update)*	DOCKET NO. 24-IEPR-03 RE: Forecast in Electricity System Planning Workshop held on Wednesday, October 2, 2024

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE FORECAST IN ELECTRICITY SYSTEM PLANNING WORKSHOP

The California Community Choice Association[1] (CalCCA) submits these Comments pursuant to the *Notice of IEPR Commissioner Workshop on Forecast Use in Electricity System Planning*, held on Wednesday, October 2, 2024.[2]

I. INTRODUCTION

CalCCA appreciates the opportunity to provide comments on the IEPR Commissioner Workshop on Forecast Use in Electricity System Planning (the Workshop). The Workshop explored how the California Energy Commission's (Commission's) Integrated Energy Policy Report (IEPR) demand forecast is used for planning by various entities, including the California Public Utilities Commission (CPUC) and California Independent System Operator (CAISO), Investor-Owned Utilities (IOU), and other Load Serving Entities (LSE) including community choice aggregators (CCAs). The Workshop highlighted significant challenges the Commission

[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 of Southern California, 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] *Notice of IEPR Commissioner Workshop on Forecast Use in Electricity System Planning*, 24-IEPR-03 (Sept. 18, 2024).

faces in producing an accurate and reliable demand forecast given increased building and transportation electrification, climate change and increased weather variability, and limited visibility into behind the meter (BTM) distributed energy resource (DER) operations.

These challenges have contributed to significant volatility in the demand forecast between IEPR demand forecast cycles, with impacts to LSEs including the exposure to greater financial risk from under- or over-procurement of Resource Adequacy (RA). Differences in assumptions and inputs between the IEPR demand forecast and LSE forecasts have also created challenges in meeting RA obligations. To lessen volatility between IEPR cycles and better align IEPR and LSE forecasts, CalCCA recommends that the Commission:

- Adopt a process to address potentially impactful volatility between IEPR demand forecast cycles through which the Commission engages with stakeholders to investigate potential inaccuracies in the assumptions when the change in the forecast falls outside of an established metric;
- Continue to engage with all LSEs to discuss accuracy of inputs and attempt to minimize the differences between the IEPR and individual LSE demand forecasts; and
- Share the draft forecast model, assumptions, and results for LSEs to review and provide feedback before the IEPR demand forecast is adopted.

II. A PROCESS SHOULD BE ADOPTED TO ADDRESS IMPACTFUL VOLATILITY BETWEEN IEPR DEMAND FORECAST CYCLES

A process should be adopted to create smooth transitions and reduce unnecessary volatility between IEPR demand forecast cycles, and the resulting negative impacts to programs and LSE obligations dependent on the forecast. In the past, forecasting demand was relatively predictable and did not result in dramatic swings from year-to-year or between IEPR cycles. Factors including the rapid electrification of the building and transportation sectors, climate change and increased weather variability, and lack of visibility into BTM DERs have introduced significant unpredictability into forecasting electric loads. The resulting volatility impacts programs and LSEs' obligations dependent on the demand forecast, including the CPUC's RA program. As a result, the Commission should adopt a process to smooth the transitions between each two-year IEPR demand forecast cycle.

Under the current practice, the Commission adopts a new demand forecast each two-year IEPR cycle. The IEPR demand forecast adopted in the first year of the cycle is the basis for the CPUC's determination of RA procurement obligations for each LSE. The IEPR demand forecast is adjusted in an IEPR Update in the second year of the IEPR cycle, which becomes the new basis for determining RA obligations in that second year. Since the IEPR Update uses the same assumptions (updated with current information) as the IEPR demand forecast for that two-year IEPR cycle, there is typically minimal volatility in the demand forecast during the two-year cycle. However, when a new IEPR forecast cycle begins the following year, new assumptions are used that can cause dramatic swings from the prior forecast. Depending on the assumptions used, the demand forecast and resulting LSE RA obligations can be either significantly higher or lower from previous years. For example, as demonstrated in Table 1 below, the RA forecast was very stable in 2019 through 2022, but then experienced significant volatility in 2023 through 2025. [3]

Table 1

	Year over Year change in Forecast (MW)							
	2018	2019	2020	2021	2022	2023	2024	2025
1-in-2 RA Forecast	(636)	(223)	(314)	70	264	1,279	749	(1,192)

For LSEs, the difficulty in predicting year-to-year changes in demand significantly impacts the ability to procure sufficient capacity to meet reliability needs under the CPUC's RA program. This volatility exposes LSEs to significant financial risk from either under- or over-

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3 California Energy Demand Forecast vintages from the 2016 IEPR through the 2023 IEPR.

procurement of RA and can impact potential retirements of the fleet of available resources needed to ensure reliability over the long term.[4]

To address this volatility, the Commission should adopt a process to review variations in IEPR demand forecast cycles. The Commission should consider adopting a metric for an acceptable level of variance between the IEPR forecast cycles. Any variance that exceeds a set percentage can trigger further discussions between the Commission and stakeholders. After such discussions, the Commission can determine if modifications to the assumptions are necessary to decrease unnecessary volatility and avoid costly under- or over-procurement.

III. THE COMMISSION SHOULD CONTINUE TO ENGAGE WITH ALL LSES TO DISCUSS ACCURACY OF INPUTS AND ATTEMPT TO MINIMIZE THE DIFFERENCES BETWEEN THE IEPR AND INDIVIDUAL LSE DEMAND FORECASTS

The Commission should continue to engage with LSEs early in the process to discuss the accuracy of inputs and attempt to minimize the LSE and IEPR forecast differences. Particularly under the new RA slice-of-day (SOD) methodology, the Commission's demand forecasts have created significant procurement challenges. Prior to 2025, the RA program was based on the peak demand forecast. Even this process involved considerable complexity as the Commission had to ensure the sum of the LSE-based demand forecasts was equal to the forecast for the system. This adjustment process can result in a forecast for which the Commission and LSE are not in mutual agreement.

In 2025, the CPUC moves to the SOD RA model. LSEs under CPUC jurisdiction are obligated to demonstrate sufficient capacity to meet all 24 individual hours of the forecast "worst

[4] In the case of a forecast for lower peak load conditions, an LSE may procure fewer resources. A resource not procured under an RA contract may be found no longer profitable and may retire. If the low demand forecast is artificial and subsequent demand forecasts return to a higher level, the retired resource may be needed for reliability but is unavailable. Without time to build new resources to replace the retired resource, system reliability can be placed in jeopardy.

day" of the month. While it was difficult to agree upon forecasts for 12 values (one for each month), it will be increasingly difficult to agree on 288 values (24 for each month). Ensuring reliability and cost-effectiveness will place significant pressure on the accuracy and predictability of the Commission demand forecast process.

As Ava Community Energy (Ava) highlighted in its presentation at the Workshop, differences between its demand forecast and the Commission's final demand forecast can have significant financial consequences. Ava stated the difference between its 2024 RA forecast and the IEPR demand forecast exceeded 100 megawatts (MW) in three months, exposing Ava to as much as $36 million for under-procurement and $3.6 million for over-procurement in high scarcity markets.[5] For the 2025 SOD forecast, Ava identified 70 month-hour slices where the difference between their forecast and the IEPR demand forecast exceeded 100 MW, and 13 month-hour slices where the deviation was greater than 200 MW.[6] This type of variance exposes LSEs to considerable financial risks, likely without a reliability benefit to the grid.

The Commission should share its demand forecast inputs, assumptions, and model results early in the process for LSE comparison. Crucial for accurate forecasting are assumptions about load modification programs such as DER programs, demand response programs, or rates resulting in load shifting. LSEs see tremendous potential for these programs, including electric vehicle charging programs, to shift peak demands. As Ava highlighted in its presentation, the Commission "should provide guidance on the assumptions already accounted for, and what should be submitted as an incremental load modifier."[7]

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[5] Ava Community Energy Workshop Presentation – *LSE Use Cases and Challenges with the RA Load Forecast* (Oct. 2, 2024), slide 5.
[6] *Id.,* slide 6.
[7] *Id.,* slide 9.

The Commission should continue to engage with LSEs early in the process, to compare and potentially revise demand forecast assumptions and results to improve forecast accuracy. Where consequential differences between Commission and LSE forecasts exist, discussions between the Commission and the LSE should occur to understand and align assumptions. The Commission should consider adopting a metric for an acceptable level of variance between an LSE's forecast and the Commission's forecast. Any variance that exceeds a set percentage should trigger further discussions between the Commission and the LSE. The Commission can also use the information gleaned from the discussions with the LSE to evaluate the overall demand forecast.

IV. THE COMMISSION'S DEMAND FORECAST MODEL, ASSUMPTIONS, AND RESULTS SHOULD BE PROVIDED TO LSES TO REVIEW AND PROVIDE FEEDBACK BEFORE THE IEPR FORECAST IS ADOPTED

Smoothing the year-to-year demand forecast and early engagement with LSEs to align inputs and assumptions will help reduce volatility and improve forecast accuracy. However, the Commission should also consider engaging with LSEs and other stakeholders after the draft forecast has been completed. Even with early engagement with LSEs, differences in modeling and inputs can still result in disparity between LSEs' forecasts and the final IEPR forecast.

The Commission should make its model available to stakeholders for review once the draft forecast is complete. This review should include all inputs, assumptions, and results[8] to allow LSEs and other stakeholders to examine and compare to their own forecasts. Current practices provide high-level summaries of forecast assumptions or results for portions of the

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[8] "Results" includes not only the forecast load values but also statistics on the model itself. For example, if using regression analysis, this would include overall significance of the model, statistical significance of each included variable, how much of the variation in load is explained by variation in the input variables, and how much autocorrelation of the data is potentially influencing the results. To the extent that certain inputs may contain confidential or proprietary information, the Commission could substitute generic assumptions based on public sources.

demand forecast in the form of PowerPoint presentations. Because of the growing importance of hourly profiles for the SOD RA framework, LSEs and other stakeholders should have the opportunity to review the detailed hourly profiles and models used to produce the profiles in draft form. The Commission should then host a workshop to allow LSEs to discuss their findings or concerns with Commission staff and propose modifications to the forecast inputs. Commission staff should make final adjustments based on these discussions with stakeholders before presenting the final IEPR forecast for adoption.

V. CONCLUSION

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

Respectfully submitted,

Leanne Bober,
Director of Regulatory Affairs and Deputy General Counsel
CALIFORNIA COMMUNITY CHOICE ASSOCIATION

October 16, 2024

California Community Choice Association

SUBMITTED 10/21/2024, 02:59 PM

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

1. **Please provide a summary of your organization's general comments on the Draft Final Proposal (DFP) and the meeting and materials shared on October 9th.**

   The California Community Choice Association (CalCCA) appreciates the opportunity to comment on the California Independent System Operator's (CAISO's) Storage Bid Cost Recovery (BCR) and Default Energy Bid (DEB) Enhancements DFP. The CAISO's proposed approach would move forward with a near-term, interim solution focused on addressing the existing incentive for storage resources to bid strategically to maximize its combined BCR and market payment. CalCCA supports the CAISO adopting an interim approach to address this existing loophole. However, BCR payments may be warranted when buy-backs or sell-backs result from the CAISO's storage market participation model, market power mitigation, or the multi-interval optimization. CalCCA appreciates the CAISO's commitment to commencing a storage initiative following the Board of Governors and Western Energy Markets Governing Body's approval of the interim solution to holistically review storage uplift, DEBs, and other issues. Within this effort, the CAISO should aim to clearly differentiate between "unwarranted" and "warranted" BCR and tailor its solution to those differences. The CAISO should immediately begin this holistic review following approval of the interim solution and, when presenting its interim solution for approval, clearly communicate a targeted time to transition from the interim solution to the longer-term solution.

   The interim approach advanced in the DFP would modify the cost proxy in the real-time BCR calculation using the formula proposed by the California Energy Storage Alliance (CESA). It adopts a modified formula for calculating proxy energy costs within the BCR calculation and proposes to apply this modified formula *in all intervals*. While the CAISO states that applying the modified formula in all intervals is necessary to eliminate the opportunity for bidding strategically to inflate BCR payments, CESA recommends, and other stakeholders support, applying CESA's proposed formula *only to a subset of intervals* in which certain triggering conditions occur. While the DFP appears to be an improvement over the status quo with a well-documented existing loophole and overly punitive proposals put forth early in this initiative, the logic behind *when* to include the modified cost proxy in the BCR calculation is not apparent. It is also not clear from the examples provided by the CAISO in the DFP or posted to the website on October 15, 2024, which approach most closely ties to when BCR is "warranted" or "unwarranted." For these reasons, CalCCA supports the adoption of the modified cost proxy as an improvement to the status quo but does not take a position on whether to apply it to the BCR calculation in all intervals or a subset of intervals. Because the interim solution is imperfect, the CAISO should expeditiously conduct its holistic review following approval of the interim solution.

2. **Please provide your organization's comments regarding the changes on the DFP relative to the Revised Straw Proposal (RSP)**

   See response in Section 1.

3. **Please provide your organization's comments regarding the proposals considered for Track 1 of the present initiative (Section 5).**

   See response in Section 1.

4. **Please provide your organization's comments regarding the issues related to local market power mitigation (LMPM) as described in the DFP and in the October 9th materials.**

   See response in Section 1.

5. **Please provide your organization's comments regarding the issues related to applicable intervals and multi-interval optimization (MIO) as described in the DFP.**

   See response in Section 1.

6. **Please provide your organization's comments regarding the Draft Final Proposal as described in Section 7 of the DFP and the materials shared on October 9th.**

   See response in Section 1.

7. **Please provide your organization's comments regarding the examples included in the DFP.**

   See response in Section 1.

8. **Please provide your organization's comments regarding the Governance Classification.**

   CalCCA supports the joint authority classification.

9. **Please provide any additional comments, feedback, or examples regarding the DFP and the October 9th stakeholder meeting. You may upload examples or data using the "Attachments" field below.**

   CalCCA has no additional comments at this time.

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 2025 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U39E)	Application 24-05-009

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING BRIEF

PUBLIC VERSION

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October 21, 2024

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SUMMARY OF RECOMMENDATIONS

- The Commission[1] should adopt CalCCA's recommended Common Cost allocation methodology, which allocates Common Costs across the ERRA, CAM and PABA based on the gross revenue requirement in each category, and to PCIA vintages based on the gross revenue requirement by vintage.

- The Commission should apply any new Common Cost allocation methodology it adopts in this proceeding starting no earlier than January 1, 2025.

- The Commission should approve PG&E's proposal to use 2018 and, if necessary, 2020 banked RECs on a first-in-first-out (FIFO) basis to meet its 2025 Minimum Retained RPS requirement, and to value the RECs it uses at the 2025 Forecast RPS Adder.

- The Commission should require PG&E's PCIA revenue requirement to: (1) reflect an agreed adjustment that spreads RA projected to be Sold or Unsold across System, Local and Flex RA categories based on the proportion of available RA by category; and (2) reflect an agreed adjustment related to an error in the amount PG&E included as the amortization of the gain on sale of PG&E's SFGO headquarters.

- The Commission should apply the legal standard discussed in this Opening Brief to the October Update.

[1] Acronyms and defined terms used in the Summary of Recommendations are defined in the body of this brief.

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 2025 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U39E)	Application 24-05-009

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
OPENING BRIEF

Pursuant to Rule 13.12 of the Rules of Practice and Procedure of the California Public Utilities Commission and the schedule adopted in the Assigned Commissioner's Scoping Memo and Ruling (Scoping Memo),[2] the California Community Choice Association[3] (CalCCA) hereby submits this opening brief in the above-captioned *Application of Pacific Gas and Electric Company (PG&E) for Adoption of Electric Revenue Requirements and Rates Associated with its 2025 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation* (Application).

The key disputed issue remaining between CalCCA and Pacific Gas & Electric Company (PG&E) in this case concerns Scoping Issue 1d, which is PG&E's proposal to modify its Common

[2] Assigned Commissioner's Scoping Memo and Ruling at 5 (Aug. 1, 2024).

[3] 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 of Southern California, 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.

Cost allocation methodology.[4] PG&E's "Common Costs" consist largely of costs associated with its Energy Policy and Procurement (EPP) personnel as those individuals spend time on bidding, scheduling, and dispatching generation resources and bundled customer load in the California Independent System Operator (CAISO) market (collectively, PG&E's Electric Supply Administration or "ESA" costs). PG&E's current methodology allocates ESA costs across three generation-related balancing accounts: the Energy Resource Recovery Account (ERRA), the Portfolio Allocation Balancing Account (PABA), and the New System Generation Balancing Account (NSGBA), based on each account's net revenue requirement (*i.e.*, costs net of benefits). That means the *value* of the generation resources in each account—including energy, Resource Adequacy (RA), and Renewable Portfolio Standard (RPS) value—impacts the magnitude of ESA costs allocated to each account.

In recent years, those impacts have been dramatic and led to unintended results. Increases in the value of PG&E's PCIA portfolio have sharply decreased the allocation of ESA costs to the PABA (and accordingly, to departed load). In fact, under the current methodology, several PABA vintages would experience the absurd result of a *negative* ESA allocation in 2025, driven by a negative net revenue requirement for those vintages. CalCCA therefore agrees PG&E's Common Cost allocation methodology must change, even though a change would cause community choice aggregator (CCA) and other departed customers to bear a relatively greater share of PG&E's ESA costs under current market conditions.

CalCCA proposes to replace the net revenue requirement allocation methodology with a gross revenue requirement allocation methodology. That methodology would continue to allocate PG&E's ESA and other Common Costs to ERRA, PABA and NSGBA, but would do so based

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4 Scoping Memo at 5.

only on the costs of the generation resources in each account, without accounting for the offsetting *value* of those resources. The gross revenue requirement methodology eliminates the impact of fluctuating energy, RA, and RPS value on ESA cost allocation, ensuring no customer group avoids paying their fair share of ESA costs when the value of PG&E's generation portfolio increases. Conversely, no customer group would be saddled with a disproportionate share of PG&E's ESA costs if the value of its portfolio decreases. Importantly, the gross revenue requirement methodology follows cost causation principles because it reasonably allocates costs based on the activities driving those costs; namely, the generation resources in PG&E's portfolio.

PG&E supported the gross revenue requirement allocation methodology just a year ago. In its prepared testimony in the 2024 ERRA Forecast proceeding, PG&E stated the gross revenue requirement methodology "align[s] cost responsibility for the ESA costs required to manage PG&E's generation-related portfolio and bundled positions with expected generation-related portfolio and bundled position costs."[5] A couple months later, in response to an ALJ ruling regarding the investor-owned utilities' (IOU) fixed generation costs, PG&E again supported the gross revenue requirement methodology. PG&E asserted the gross revenue requirement methodology "eliminate[s] the risk that bundled service customers bear a disproportionate share of [Common Costs]", asserted that methodology is "supported by statutory requirements to prevent cost shifting" and argued that methodology "will ensure that all customers bear an equitable portion of costs to manage the shared generation portfolio."[6]

Since that testimony, however, PG&E's Common Cost allocation proposal has been a moving target. In Track 2 of its 2024 ERRA Forecast proceeding, PG&E retreated from its original

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5 Application (A.) 23-05-012, PG&E Prepared Testimony at 9-10 to 9-11.

6 A.23-05-012, PG&E Response to Administrative Law Judge's Ruling Directing Parties to Comment Regarding Fixed Generation Costs at 7 (Aug. 16, 2023).

proposal, and proposed to allocate not only ESA costs but also other non-ESA common costs to the Legacy Utility-Owned Generation (UOG) vintage subaccount of the PABA. Now, PG&E proposes to revert the allocation of non-ESA Common Costs to the net revenue requirement methodology, and largely split ESA costs between the Legacy UOG and 2009 PCIA vintages based on the General Rate Case (GRC) revenue requirement of resources in those vintages. In defense of its proposal, PG&E asserts it wants to align its ESA cost allocation approach with Southern California Edison's (SCE) "approved" methodology, but ignores that the Commission has not, in fact, approved SCE's ESA cost allocation methodology.

The Commission should reject PG&E's ESA cost allocation proposal for two main reasons. First, unlike CalCCA's proposed gross revenue requirement methodology, which spreads ESA costs across the generation-related balancing accounts driving those costs, PG&E's proposal deviates sharply from cost causation principles. PG&E does not track or delineate its ESA costs based on the generation resource or customer type driving the cost, so there is no way for the Commission to perfectly match cost allocation with cost causation in this case. However, PG&E acknowledges that it incurs ESA costs in bidding, scheduling and dispatching *all* generation resources (including non-PCIA portfolio resources that serve bundled customers only), as well as bundled load. That means a portion of PG&E's ESA costs are incurred on activities that provide <u>no benefit</u> to unbundled customers. By allocating the vast majority of ESA costs to the PCIA, PG&E's proposed methodology would force unbundled customers to pay for costs that were not incurred on their behalf, violating the ratepayer indifference principle in Sections 365.2 and 366.2 of the California Public Utilities Code.

Second, PG&E's proposal would create a new cost shift. Under that proposal, PCIA-exempt customers would pay for a vanishingly small fraction of ESA costs—those allocated to

CAM based on the GRC revenue requirements associated with a single CAM utility-owned generation (UOG) resource. By arbitrarily limiting its CAM allocation based on the GRC revenue requirements of a single resource, PG&E would unfairly force departed and bundled customers paying the PCIA to cover operations and maintenance (O&M) costs PG&E incurs to serve PCIA-exempt customers. In contrast, the gross revenue requirement methodology CalCCA proposes would allocate ESA costs to all customers (including PCIA-exempt customers) by spreading costs to ERRA, PABA, and CAM based on the costs of the *entire* generation portfolio in each account. That approach is more equitable than PG&E's methodology because PG&E's entire generation portfolio drives ESA costs, not a subset of that portfolio.

The Commission should therefore reject PG&E's proposed Common Cost allocation methodology and adopt CalCCA's proposed gross revenue requirement methodology. Further, the Commission should reject PG&E's request to apply modifications to its Common Cost allocation methodology *retroactively*, effective January 1, 2024. In essence, PG&E recommends the Commission use the 2024 true-up to modify revenue requirements approved in PG&E's 2024 ERRA Forecast proceeding based on a methodology approved in this year's proceeding. But that approach would abuse the true-up. The purpose of the true-up in ERRA Forecast proceedings is to reconcile actual costs and revenues in the current year with forecasted costs and revenues included in rates, such that PG&E can timely address an under- or over-collection. The true-up is not an opportunity for PG&E to retroactively unsettle authorized revenue requirements simply because it did not get the result it wanted in the prior year's proceeding. Moreover, while PG&E raised the common cost allocation issue in its 2024 ERRA Forecast proceeding, as mentioned above, PG&E's allocation proposal in that proceeding does not resemble the one it makes in the instant case. PG&E has offered no valid reason for the Commission to retroactively apply a common cost allocation methodology PG&E did not even propose in last year's proceeding. The Commission should reject PG&E's request to engage in retroactive ratemaking and apply any change to PG&E's allocation proposal prospectively.

This brief also discusses three uncontested issues PG&E has committed to addressing in its Fall Update.

First, in its rebuttal testimony, PG&E explains it executed sales agreements for 2025 RPS energy and RECs following the submission of its prepared testimony (in which it forecast **<u>excess</u>** RPS-eligible generation in 2025), which now leads PG&E to forecast an RPS **<u>deficiency</u>** relative to its Minimum Retained RPS requirement for 2025. In response to CalCCA discovery on this issue, PG&E confirmed it anticipates using RECs banked in 2018 and—to the extent necessary—2020 to cover its shortfall and plans to value the RECs it uses at the 2025 Forecast Adder. PG&E also confirmed it will exhaust RECs banked in 2018 before using 2020 RECs, consistent with the "first-in-first-out" (FIFO) approach approved in PG&E's 2024 ERRA Forecast proceeding. CalCCA agrees PG&E's intended approach to satisfying its Minimum Retained RPS requirement is appropriate and will review PG&E's updated Indifference Amount calculation in its Fall Update testimony.

Second, PG&E agrees with CalCCA witness Dickman's recommendation that PG&E spread Residual RA sales and Unsold RA forecast volumes across System, Flexible and Local RA based on the available forecast proportion of each category. PG&E expects this adjustment will decrease its PCIA revenue requirement by approximately $68.6 million and will reflect the adjustment in its Fall Update testimony.

Third, in response to CalCCA witness Dickman's testimony observing PG&E used an incorrect allocation factor to determine the electric generation portion of the net gain on its sale of its San Francisco General Office (SFGO) headquarters, PG&E agreed to correct the error in its Fall Update testimony. Correcting this error reduces the 2025 Indifference Amount by $8 million and reduces ERRA and CAM revenue requirements by $0.3 million.

I. BURDEN OF PROOF AND LEGAL STANDARD

The magnitude of the impact of PG&E's application on both departed and bundled customers requires cautious and careful consideration under the applicable standards of proof. As the ratemaking applicant, PG&E has the burden of affirmatively establishing the reasonableness of all aspects of its application.[7] That burden of proof includes a burden of production, which in ERRA Forecast proceedings is a "preponderance of the evidence."[8] That means the Commission should not grant the relief PG&E requests unless a preponderance of the record evidence demonstrates PG&E has affirmatively satisfied its burden of proof with respect to that request.

The Scoping Memo categorized this proceeding as ratesetting.[9] The Commission has previously determined that Section 1757 of the Public Utilities Code applies to ratesetting,[10] which means the final decision must be "supported by the findings," and those findings must be "supported by substantial evidence in light of the whole record." That means they must be based on the record or inferences reasonably drawn from the record.[11] As a result, the Commission

7 Decision (D.) 23-08-027 at 15 (Aug. 10, 2023).

8 *See, e.g.*, D.18-01-009 at 9-10 (Jan. 16, 2018); D.15-07-044 at 29 (Jul. 27, 2015) (observing that the Commission has discretion to apply either the preponderance of evidence or clear and convincing standard in a ratesetting proceeding, but noting that the preponderance of evidence is the "default standard to be used unless a more stringent burden is specified by statute or the Courts.")

9 Scoping Memo at 6.

10 Cal. Pub. Util. Code § 1757; *see, e.g.* D.20-05-027 at 5-6 (May 8, 2020) (stating "As an initial matter, SDG&E cites to the wrong statute, because Public Utilities Code section 1757.1 does not set forth the applicable standards for a ratesetting proceeding like this one. Rather, section 1757 provides the appropriate standard and requires a finding as to whether the Commission's findings are not supported by substantial evidence in light of the whole record.").

11 *See, e.g.* D.20-05-027 at 6.

cannot grant the relief in PG&E's Application without substantial evidence to support the rates requested.[12] California courts will overturn Commission decisions that lack substantial evidence.[13] Mere rubber-stamping of uncorroborated, disputed evidence does not meet this standard.[14] The Commission, therefore, must reject the components of PG&E's Application that are not supported by substantial evidence.

In addition, pursuant to Public Utilities Code Section 451:

> All charges demanded or received by any public utility, or by any two or more public utilities, for any product or commodity furnished or to be furnished or any service rendered or to be rendered shall be just and reasonable. Every unjust or unreasonable charge demanded or received for such product or commodity or service is unlawful.[15]

This foundational "just and reasonable" statutory requirement is applicable to all rates and charges, including those that will be established by this ERRA Forecast proceeding. Commission precedent supports cost-causation principles in setting "just and reasonable" rates, whereby customers are responsible for the costs incurred on their behalf.[16] The Public Utilities Code also requires rates to be non-discriminatory. Public utilities are prohibited from establishing "any unreasonable difference as to rates, charges, service, facilities, or in any other respect, either as between localities

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12 Cal. Pub. Util. Code § 1757(a)(4). *See, e.g. The Utility Reform Network v. Pub. Util. Comm'n*, 223 Cal. App. 4th 945, 958-59 (Feb. 5, 2014).

13 *Id*.

14 *Id*.

15 Cal. Pub. Util. Code § 451.

16 D.15-07-001 at 2 (Jul. 13, 2015) (citing *K N Energy, Inc. v. F.E.R.C.*, 968 F.2d 1295, 1300 (D.C. Cir. 1992) ("[I]t has been traditionally required that all approved rates reflect to some degree the costs actually caused by the customer who must pay them."); *Alabama Elec. Co-op., Inc. v. F.E.R.C.*, 684 F.2d 20, 27 (D.C. Cir. 1982) ('[I]t has come to be well established that electrical rates should be based on the costs of providing service to the utility's customers, plus a just and fair return on equity."); *So. Cal. Edison Authorized to Increase Rates for California Intrastate Electric Services*, 75 CPUC 641 (1973) (recognizing the desirability of each group's bearing its fair share of the cost of service, as such share is measured by the cost of service study); D.10-09-010 (Sept. 2, 2010). The decision further notes; "For this reason a cost of service study is part of each general rate case for establishing electricity rates." D.15-07-001 at 2-3 n.3.

or as between classes of service."[17]

With respect to the legal standards governing this proceeding, California law prohibits cost shifts between groups of bundled and unbundled customers, as PG&E emphasizes in its Application.[18] Section 365.2 of the California Public Utilities Code mandates indifference for departed customers, requiring the Commission to "ensure that departing load does not experience any cost increases as a result of an allocation of costs that were not incurred on behalf of the departing load."[19] Under Section 366.2, unbundled customers are responsible solely for "estimated net unavoidable electricity costs" when determining indifference, and those costs must be reduced by the benefits in the IOUs' portfolios that accrue to bundled customers.[20]

Finally, in the Commission's unique ERRA Forecast applications, where policymaking is largely forbidden,[21] the utility rarely requests the recovery of costs that have not already been approved via a prior decision, and the allocation of costs among different customer groups and classes is pre-determined via the utility's GRC. Instead, the Commission implements prior decisions, resolving any ambiguity in those decisions necessary to enact rates for the forecast year.

Here, however, PG&E has requested changes to the policies underlying its ratemaking: namely, how it should allocate its "Common Costs." Thus, not only must PG&E's proposed PCIA revenue requirement and rates comply with all applicable rules, regulations, resolutions, and decisions for all customer classes, the Commission must now also consider whether PG&E's new common cost allocation proposal is reasonable, whether it illegally shifts costs to other customers,

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17 Cal. Pub. Util. Code § 453(c).

18 Amended Application at 10-11.

19 Cal. Pub. Util. Code § 365.2.

20 Cal. Pub. Util. Code §§ 366.2 (f)(2), (g).

21 D.18-01-009 at 10 (finding that policy issues and other industry-wide practices such as changes to the PCIA methodology are properly addressed in rulemaking dockets, such as R.17-06-026).

and/or whether it should be considered and resolved in a rulemaking proceeding where all three IOUs are present.[22] For the reasons stated below, PG&E's proposal is unjust and unreasonable, results in cost shifts, and would be better considered in a rulemaking where all three IOUs are parties.

II. BACKGROUND

CCA customers receive generation services from their local CCA, and receive transmission, distribution, billing, and other services from the incumbent, for-profit utility.[23] CCA customers pay CCA-specific generation rates, which are partially influenced by local mandates to procure and maintain clean electricity portfolios that in many cases exceed state requirements for renewable generation.[24] CCA and other unbundled customers are subject to several nonbypassable charges (NBC), including PCIA rates to recover above market costs of the utility's PCIA-eligible resources, as well as the New System Generation Charge (NSGC) rate to recover CAM costs.[25]

The Commission adopted the PCIA to ensure that when customers of IOUs depart from bundled service and receive their electricity from a non-IOU provider, such as a CCA, "those customers remain responsible for costs previously incurred on their behalf by the IOUs — but only those costs."[26]

The PCIA revenue requirement is derived from two sources in each utility's ERRA forecast case.[27] The first is the Indifference Amount forecasted for the year *for which* rates are being set,

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22 *See, e.g.*, Scoping Memo at 3.

23 Exh. CalCCA-01C at 4.

24 *Id*.

25 *Id*.

26 *See* R.17-06-026, *Scoping Memo and Ruling of Assigned Commissioner*, p. 2 (Sept. 25, 2017); D.18-10-019 at 3.

27 Exh. CalCCA-01C at 4.

i.e., the Indifference Amount forecasted for 2025 in the instant proceeding.[28] The second is the balance in the PABA the utility anticipates seeing at the end of the year *in which* rates are being set, *i.e.*, the 2024 year-end balance in the instant proceeding.[29] Figure 1 below demonstrates the relationship between the PCIA revenue requirement, the Indifference Amount, and the year-end PABA balance.

FIGURE 1[30]

The utility updates the Indifference Amount annually in each year's ERRA Forecast proceeding.[31] The Indifference Amount is the difference between the forecasted cost of the IOU's supply portfolio in the target year (here, 2025) and the forecasted market value of the IOU's supply portfolio in the target year,[32] as demonstrated in Figure 2.

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28 *Id.*

29 *Id.*

30 *Id.* at 5.

31 *Id.*

32 *Id.*

FIGURE 2[33]

Total Portfolio Cost includes capital investment recovery and fixed operations and maintenance costs determined in a GRC for UOG, but also includes the costs of purchased power such as that from power purchase agreements (PPA), fuel costs for UOG and PPAs with tolling agreements, and California Independent System Operator (CAISO) grid charges and revenues, net of any sales.[34]

Portfolio Market Value is derived by multiplying the energy and/or capacity output from eligible generation by the MPBs.[35] The MPBs are an administratively determined set of proxy values that represent the market value of the IOU's resource portfolio.[36] Portfolio Market Value consists of three principal components: Energy Value, RPS Value, and RA Value.[37]

- Energy Value is the estimated financial value, measured in dollars, that is attributed to the generation energy-only component of a utility portfolio for a given year.[38]

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33 *Id.*

34 *Id.* (citing D.11-12-018 at 8-9 (Dec. 1, 2011)).

35 *Id.*

36 D.19-10-001 at 6 ("Market Value is the estimated financial value, measured in dollars, that is attributed to a utility portfolio of energy resources for the purpose of calculating the Power Charge Indifference Adjustment for a given year.").

37 Exh. CalCCA-01 at 6.

38 D.19-10-001 at 6.

- RPS Value is the estimated financial value, measured in dollars, that is attributed to the renewable energy component of a utility portfolio for a given year above and beyond the Energy Value.[39]

- RA Value is the estimated financial value, measured in dollars, that is attributed to the resource adequacy component of a utility portfolio for a given year.[40]

MPBs are estimates of the value per unit (not total portfolio value) associated with the three principal sources of value in utility portfolios (non-RPS energy, RPS energy, and RA capacity).[41] Each MPB must be multiplied by the relevant portfolio volume to calculate the Energy, RPS, and RA Values underlying the overall Portfolio Market Value:[42]

- Energy Index is the MPB that reflects the estimated market value of each unit of energy in a utility portfolio, in dollar value per megawatt hour ($/MWh). It is sometimes referred to as "Brown Power Index", "Brown Power component", "Brown Power Adder", or "Brown Power benchmark."[43]

- RPS Adder is the MPB that reflects the estimated incremental value of each unit of RPS-eligible energy in $/MWh.[44]

- RA Adder is the MPB that reflects the estimated value of each unit of capacity in a utility portfolio that can be used to satisfy Resource Adequacy obligations, in dollar value per kilowatt-month ($/kW-month). The RA Adder has three subcomponents, reflecting each type of RA product required for compliance with the RA program, system, local, and flex, which each have a separate RA Adder.[45]

Together, the Total Portfolio Cost and Portfolio Market Value are the forward-looking, forecasted ingredients that constitute the Indifference Amount portion of the PCIA revenue requirement.[46]

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39 *Id*.

40 *Id*.

41 *Id*.

42 *Id*.

43 *Id*. at 7.

44 *Id*.

45 *Id*.

46 Exh. CalCCA-01C at 7.

The second ingredient, the year-end PABA balance, is largely backward-looking in that it trues up forecasted values from the prior ERRA forecast case with actual values the utility has realized to date.[47] Prior to D.18-10-019, the PCIA rate was set only on a forecast basis with no after-the-fact true-up for unbundled customers.[48] Decision 18-10-019 approved a true-up for the PCIA using actual recorded above-market costs for PCIA-eligible resources and billed revenues from both bundled and unbundled customers.[49] This true-up now occurs via the PABA and is a rolling true-up between the forecasted costs and revenues used to determine the Indifference Amount and the actual costs and revenues PG&E realizes during the year related to its PCIA-eligible resource portfolio.[50]

To recover PCIA costs from customers, each generation resource and departing customer is assigned a "vintage."[51] To determine the appropriate resources associated with each vintage, a distinct portfolio of generation resources is identified for each vintage year based on when the commitment to procure each resource was made.[52] To determine the appropriate vintage for unbundled customers, customers are assigned to vintage years according to the date they departed

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47 *Id*. Because the true-up for 2024 occurs during 2024, this true-up is developed using (1) actual values that are available to date and (2) a forecast of actual values for the remainder of the year. PG&E's Application includes an estimate of the 2024 year-end PABA balance comprising a combination of actual entries from January through March 2024 and a projection of activity from April through December 2024. PG&E's October Update should include an estimate of the 2024 year-end PABA balance comprising a combination of actual entries from January through August 2024 and a projection of activity from September through December 2024. The final December 31, 2024, advice letter implementing the proceeding will include actual entries. *Id*. at 7, footnote 13.

48 *Id*. at 7.

49 *Id*.

50 *Id*.

51 *Id*. at 8.

52 *Id*.

bundled IOU service.[53] Customers continuing to receive bundled service from the IOU are included in the latest vintage (*e.g.*, vintage 2025 in the current application).[54] Each vintage is assigned both a separate Indifference Amount and a separate year-end PABA balance,[55] and customers are responsible for the cumulative Indifference Amount for years prior to and including their vintage.[56] The PCIA revenue requirement is allocated among both bundled and unbundled customers based on their vintage and their rate class using the allocation factors from PG&E's most recently approved GRC.[57]

Unlike unbundled customers, bundled customers receive all electric services from the IOU, including generation, transmission, distribution, billing, and other services. Bundled customers pay a commodity rate to recover the generation portion of the IOU revenue requirement not included in other rates or surcharges – like unbundled customers, bundled customers are subject to certain NBCs, such as the NSGC for CAM costs. Bundled customers also pay their share of above-market costs of the utility's PCIA-eligible resources.[58] However, rather than pay a specified PCIA charge, PG&E includes bundled customers' share of PCIA-related costs in the generation revenue requirement.[59] These costs are recovered through the bundled generation rate.[60]

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53 Unlike portfolio resources, customers are assigned to vintages using a July to June calendar period. For example, customers departing bundled service between July 2019 and June 2020 are assigned to the 2019 vintage. *Id*. at 8, footnote 14.

54 *Id*. at 8.

55 D.11-12-018 at 9.

56 Exh. CalCCA-01C at 8.

57 D.18-10-019 at 122 and Ordering Paragraph (OP) 4.

58 Exh. PG&E-2C at 10-10.

59 *Id*.

60 D.20-03-019 at OP 2.

PG&E's Common Costs impact the total portfolio costs that underlie the Indifference Amount. All other things equal, if additional common costs are recovered via PCIA rates, then the PCIA portion of customers' power supply rates will increase.[61] Accordingly, it is important to allocate these costs equitably and in line with principles of cost causation to ensure that costs are not improperly shifted between customer groups.

III. CONTESTED ISSUE (SCOPING ISSUE 1D): THE COMMISSION SHOULD REJECT PG&E'S EVER-SHIFTING PROPOSAL TO MODIFY ITS COMMON COST ALLOCATION METHODOLOGY, AND SHOULD INSTEAD ADOPT CALCCA'S PROPOSED ALLOCATION METHODOLOGY

A. Whereas PG&E's Common Cost Allocation Proposal Keeps Changing, CalCCA Has Consistently Supported Allocating Common Costs Based on the Gross Revenue Requirement Methodology

PG&E incurs certain "Common Costs" related to its procurement activities. Common Costs include ESA costs and carrying costs related to collateral requirements and GHG emissions compliance instruments (collateral costs).[62] PG&E's EPP organization incurs ESA costs as it spends time on bidding, scheduling, and/or dispatching resources and load in the CAISO market.[63] Collateral costs reflect the short-term cost of borrowing when PG&E posts cash or a letter of credit to counterparties when it transacts in the wholesale market.[64]

PG&E currently allocates Common Costs among the ERRA, NSGBA (also known as the CAM), and PABA balancing accounts, and to PCIA vintages within PABA. PG&E allocates Common Costs based on the revenue requirement approved for each account, net of the wholesale market value of the resources corresponding to each account (*i.e.*, market value of the resources'

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61 *See* PG&E-2C at 10-10.

62 Exh. CalCCA-01C at 9.

63 *Id.*; Exh. CalCCA-01C, Attachment B (PG&E's response to CalCCA data request 1.27).

64 Exh. CalCCA-01C at 9; Exh. CalCCA-01C, Attachment B (PG&E's response to CalCCA data request 1.17).

energy, RA, and RPS) (net revenue requirement methodology).[65] But as a result of recent increases in the market value of its PCIA portfolio—which result in a relatively smaller Common Cost allocation to the PCIA, and as a result, to departing load—PG&E now wants to abandon its current Common Cost allocation methodology.[66] PG&E's proposed replacement for that methodology, however, has been a moving target. PG&E has made at least three different proposals on this issue over the last two years.

PG&E first raised this issue in its 2024 ERRA Forecast proceeding. In that case, PG&E proposed to refine its ESA cost allocation methodology by calculating allocation factors based only on the cost component of revenue requirements associated with each generation-related balancing account, *i.e.*, the gross revenue requirement before netting out wholesale market value (gross revenue requirement methodology).[67] At that time, PG&E argued its proposal aligned "cost responsibility for the ESA costs required to manage PG&E's generation-related portfolio and bundled positions with expected generation-related portfolio and bundled position costs."[68] PG&E also stated the gross revenue requirement methodology "eliminate[s] the risk that bundled service customers bear a disproportionate share of [Common Costs]", asserted that methodology is "supported by statutory requirements to prevent cost shifting" and argued that methodology "will ensure that all customers bear an equitable portion of costs to manage the shared generation portfolio."[69]

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65 Exh. PG&E-02C at page 10-9, lines 12-15.

66 Exh. CalCCA-01C at 10.

67 *Id*.

68 *Id*. at 10-11 (citing PG&E prepared testimony, Chapter 9, pages 9-10 to 9-11 in PG&E's 2024 ERRA Forecast Application proceeding, A.23-05-012).

69 A.23-05-012, PG&E Response to Administrative Law Judge's Ruling Directing Parties to Comment Regarding Fixed Generation Costs at 7 (Aug. 16, 2023).

PG&E's Common Cost allocation proposal was ultimately deferred to a second track of the 2024 ERRA Forecast proceeding. But by the time PG&E submitted a prehearing conference statement in that proceeding in early 2024, PG&E's proposal had changed. In that statement, PG&E proposed that Common Costs—including not only ESA costs but also collateral costs—should be recovered through the Legacy UOG vintage of the PCIA.[70] PG&E asserted that its new proposal was consistent with SCE's approach to allocating ESA costs.[71]

"Version 2.0" of PG&E's Common Cost allocation proposal was ultimately deemed outside the scope of Track 2 of PG&E's 2024 ERRA Forecast proceeding. So, PG&E made the same proposal in its prepared testimony in this proceeding. Specifically, PG&E proposed to allocate Common Costs entirely to the Legacy UOG vintage of the PCIA and allocate those costs to PCIA-eligible bundled and departed load customers in proportion to their respective sales volume.[72]

By the time PG&E filed rebuttal testimony in this proceeding just months after filing its prepared testimony, however, PG&E's proposal had changed again (Version 3.0). In rebuttal testimony, PG&E proposes to "refine its proposed allocation methodology to accurately reflect SCE's adopted methodology"[73] consistent with CalCCA's description of that methodology. Specifically, PG&E proposes to split ESA costs between the Legacy UOG and 2009 PCIA vintages.[74] In response to a CalCCA discovery request, PG&E confirmed its "refined"

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[70] Exh. CalCCA-01C at 11.

[71] *Id*. (citing PG&E's Prehearing Conference Statement at page 5 in A.23-05-012).

[72] Exh. PG&E-02C, Chapter 10, page 10-13.

[73] Exh. PG&E-03 at 19; *see also* Exh. CalCCA-02C (PG&E response to CalCCA discovery request 4.06, confirming PG&E proposes to change its allocation methodology to reflect the methodology described at A42 (Exh. CalCCA-01C at 18:27-19:12) in CalCCA's direct testimony and at Table 1 in A48 of the same testimony).

[74] Exh. PG&E-3 at 19.

methodology allocates ESA costs to CAM and PCIA vintages based on the account and vintage assignment of the UOG revenue requirement approved in PG&E's 2023 GRC.[75] PG&E also clarified that under Version 3.0 of its proposal, it no longer proposes to allocate collateral costs to the Legacy UOG vintage of the PCIA, and instead proposes to allocate those costs to ERRA, PABA and CAM based on the net revenue requirement methodology (while allocating to the vintages within PABA based on gross revenue requirements).[76] However, in the same discovery response, PG&E stated it "will evaluate whether CalCCA's recommendation of using the gross methodology to allocate non-ESA Common Costs is appropriate", suggesting a Version 4.0 of PG&E's Common Cost allocation methodology may be forthcoming.

To be clear, CalCCA agrees with PG&E that allocating Common Costs based on net revenue requirements may produce unintended results as the market value of PG&E's PCIA portfolio increases. For example, under the net revenue requirement method, PG&E allocates its 2025 ESA costs based on generation-related balancing accounts' authorized net revenue requirements from the 2024 ERRA Forecast case which included a *negative* PCIA. As a result, more than 100% of ESA costs would be allocated to ERRA and NSGBA as shown in Table 1 below.

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[75] PG&E also explained that a small portion of its ESA Common Costs corresponding to PG&E's Core Gas supply would be allocated to ERRA, because gas rates are not in scope in this proceeding. Exh. CalCCA-02C (PG&E response to CalCCA discovery request 4.07).

[76] Exh. CalCCA-02C (PG&E response to CalCCA discovery request 4.08).

Table 1: Common Cost Allocation - Net Revenue Requirement Method[77]

Cost Recovery		Authorized 2024 Cost without RF&U (Market Value is Included)				Common Cost Allocation Factors	2025 Energy Supply Administration (ESA) Cost ($000)	2025 Collateral and Interest Expense ($000)
		CAM $000	PCIA $000	ERRA $000	Total $000			
ERRA	ERRA			4,421,013	4,421,013	98.65%	91,664	6,344
NSGBA	NSGC	378,527			378,527	8.45%	7,088	543
PABA	UOG Legacy		(266,879)		(266,879)	-5.96%	(4,997)	(383)
PABA	Vin 2009		368,924		368,924	8.23%	6,908	529
PABA	Vin 2010		145,855		145,855	3.25%	2,731	209
PABA	Vin 2011		(2,739)		(2,739)	-0.06%	(51)	(4)
PABA	Vin 2012		(20,731)		(20,731)	-0.46%	(388)	(30)
PABA	Vin 2013		(37,143)		(37,143)	-0.83%	(695)	(53)
PABA	Vin 2014		(3,822)		(3,822)	-0.09%	(72)	(5)
PABA	Vin 2015		(7,084)		(7,084)	-0.16%	(133)	(10)
PABA	Vin 2016		(2,300)		(2,300)	-0.05%	(43)	(3)
PABA	Vin 2017		(18,596)		(18,596)	-0.41%	(348)	(27)
PABA	Vin 2018		(64,528)		(64,528)	-1.44%	(1,208)	(93)
PABA	Vin 2019		(75,245)		(75,245)	-1.68%	(1,409)	(108)
PABA	Vin 2020		(1)		(1)	0.00%	0	(0)
PABA	Vin 2021		(311,154)		(311,154)	-6.94%	(5,826)	(446)
PABA	Vin 2022		(22,222)		(22,222)	-0.50%	(416)	(32)
PABA	Vin 2023		(540)		(540)	-0.01%	(10)	(1)
	Total	378,527	(318,206)	4,421,013	4,481,333	100.00%	92,793	6,430

ERRA	91,664	6,344
NSGBA	7,088	543
PABA	(5,959)	(457)
	92,793	6,430

For that reason, CalCCA largely supported Version 1.0 of PG&E's proposal to modify its Common Cost allocation methodology—the gross revenue requirement methodology—when PG&E first made that proposal in its 2024 ERRA Forecast proceeding, even though that methodology would increase the proportion of PG&E's Common Costs paid by CCA and other unbundled customers.[78] And CalCCA has consistently supported the gross revenue requirement methodology since that time, including in this proceeding.

77 Exh. CalCCA-01C at 12, Attachment B (PG&E's response to CalCCA data request 1.21).

78 *Id*. at 11 (citing CalCCA's direct testimony in PG&E's 2024 ERRA Forecast case).

Under the gross revenue requirement methodology, PG&E would spread its Common Costs to all generation-related balancing accounts (consistent with version 1.0 of PG&E's proposal), and across PCIA vintages based on the gross revenue requirements of the resources associated with those accounts and vintages.[79] As PG&E itself argued in its 2024 ERRA Forecast proceeding, the gross revenue requirement allocation methodology aligns allocation of ESA costs with cost causation principles and results in a more equitable distribution of costs across the broader group of applicable customers.[80] Further, as PG&E correctly argued in that proceeding, the gross revenue requirement methodology is consistent with Energy Division's disposition of Advice Letter (AL) 5440-E which implemented the PABA and specified allocation of ESA costs would be based on the authorized revenue requirement in each account.[81] Finally, allocating Common Costs based on gross revenue requirements also ensures that changes in the market value of generation attributes does not affect the allocation of Common Costs across balancing accounts and PCIA vintages, reducing volatility in Common Cost allocations.[82] CalCCA's proposed allocation methodology is therefore fair and equitable, and produces just and reasonable rates consistent with the requirements of Section 451 of the Public Utilities Code.[83]

Table 2 below shows the Common Cost Allocation factors based on the gross revenue requirements approved in PG&E's 2024 ERRA Forecast proceeding:

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79 *Id*. at 14.

80 *Id*. at 16 (citing PG&E testimony from 2024 ERRA Forecast proceeding).

81 *Id*. (citing PG&E testimony from 2024 ERRA Forecast proceeding).

82 *Id*. at 16.

83 Cal. Pub. Util. Code § 451.

Table 2: Common Cost Allocation Factors - Gross Revenue Requirement Method[84]

Cost Recovery		Authorized 2024 Cost without RF&U (Market Value is Excluded)				Common Cost Allocation Factors	2025 Energy Supply Administration (ESA) Cost ($000)	2025 Collateral and Interest Expense ($000)
		CAM $000	PCIA $000	ERRA $000	Total $000			
ERRA	ERRA			2,718,617	2,718,617	35.08%	32,554	2,256
NSGBA	NSGC	421,569			421,569	5.44%	5,048	350
PABA	UOG Legacy		2,050,450		2,050,450	26.46%	24,553	1,701
PABA	Vin 2009		1,698,255		1,698,255	21.92%	20,336	1,409
PABA	Vin 2010		414,546		414,546	5.35%	4,964	344
PABA	Vin 2011		119,579		119,579	1.54%	1,432	99
PABA	Vin 2012		142,534		142,534	1.84%	1,707	118
PABA	Vin 2013		48,193		48,193	0.62%	577	40
PABA	Vin 2014		5,391		5,391	0.07%	65	4
PABA	Vin 2015		9,994		9,994	0.13%	120	8
PABA	Vin 2016		1,974		1,974	0.03%	24	2
PABA	Vin 2017		9,953		9,953	0.13%	119	8
PABA	Vin 2018		0		0	0.00%	0	0
PABA	Vin 2019		17,001		17,001	0.22%	204	14
PABA	Vin 2020		(1)		(1)	0.00%	(0)	(0)
PABA	Vin 2021		91,134		91,134	1.18%	1,091	76
PABA	Vin 2022		(455)		(455)	-0.01%	(5)	(0)
PABA	Vin 2023		463		463	0.01%	6	0
	Total	421,569	4,609,012	2,718,617	7,749,198	100.00%	92,793	6,430

ERRA	32,554	2,256
NSGBA	5,048	350
PABA	55,191	3,824
	92,793	6,430

While CalCCA's proposal uses gross revenue requirements from last year's ERRA Forecast proceeding (consistent with PG&E's original proposal), CalCCA notes an additional improvement to its allocation methodology would be to use the gross revenue requirement forecasted in the current year, updated each year. Doing so would best match cost allocation with projected costs and benefits. Exh. CalCCA-01C at 15.

Table 3 below compares the Common Costs allocated to each balancing account using the net revenue requirement and gross revenue requirement allocation methods. This demonstrates a gross revenue requirement allocation method shifts a significant portion of PG&E's Common

84 Exh. CalCCA-01C at 15.

Costs out of ERRA (recovered exclusively from bundled customers) into PABA (recovered from both bundled and unbundled customers).

Table 3: Common Cost Allocation - Gross vs. Net Revenue Requirement[85]

Net Revenue Requirement Allocation

	ESA Costs	Collateral Costs	Total
ERRA	91,664	6,344	98,008
NSGBA	7,088	543	7,631
PABA	(5,959)	(457)	(6,416)
	$ 92,793	$ 6,430	$ 99,223

Gross Revenue Requirement Allocation

	ESA Costs	Collateral Costs	Total
ERRA	32,554	2,256	34,810
NSGBA	5,048	350	5,398
PABA	55,191	3,824	59,015
	$ 92,793	$ 6,430	$ 99,223

Difference (Gross - Net)

	ESA Costs	Collateral Costs	Total
ERRA	(59,110)	(4,088)	(63,198)
NSGBA	(2,040)	(193)	(2,233)
PABA	61,150	4,281	65,431
	$ -	$ -	$ -

As shown in Table 3, CalCCA's approach would reduce the ERRA revenue requirement by $63.1M and increase the PABA revenue requirement by $65.4M.

B. Having Retreated from Its Original, Principled Proposal, PG&E Now Seeks Only to Match SCE's Unsanctioned ESA Cost Allocation Methodology

Whereas PG&E's original proposal to change its Common Cost allocation methodology (Version 1.0) was a principled approach to address certain unintended impacts associated with the net revenue requirement allocation methodology, PG&E's subsequent proposals have largely been motivated by its desire to match (what it perceives to be) SCE's allocation approach. In its prepared

85 *Id*. at 17.

testimony, PG&E asserts its proposal to assign Common Costs to the Legacy UOG PCIA vintage is consistent with SCE's authorized approach for recovering the equivalent costs.[86] In a similar vein, in response to a CalCCA discovery request asking PG&E why it changed its position regarding the allocation of Common Costs, PG&E responded that it determined "SCE's established methodology is the most appropriate and consistent with the current ERRA cost recovery structure."[87] Then, after CalCCA witness Dickman explained that the Common Cost allocation proposal described in PG&E's prepared testimony *does not*, in fact, match SCE's approach,[88] PG&E changed its proposal in rebuttal testimony to "accurately reflect SCE's adopted methodology[.]"[89] According to PG&E, matching SCE's methodology is a worthwhile objective because "there is no reason that common cost allocation practices for indirect resource costs, like ESA and other Common Costs, should differ between PG&E and SCE."[90]

PG&E's reasoning suffers from two flaws. First, whereas CalCCA certainly agrees the IOUs' Common Cost allocation practices should align (and for that reason, has previously recommended the Commission evaluate those practices in a rulemaking or other consolidated proceeding where all three IOUs are respondents[91]) CalCCA does not support alignment for alignment's sake. Rather, the IOUs should align on an allocation methodology that equitably distributes those common costs among customers and produces just and reasonable rates. Second, PG&E mischaracterizes SCE's allocation methodology where it describes that methodology as

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86 Exh. PG&E-02C at Chapter 10, page 10-11.

87 Exh. CalCCA-01C, Attachment B (PG&E's response to CalCCA discovery request 1.36).

88 *Id*. at 18-19.

89 Exh. PG&E-3 at 19.

90 *Id*. at 21.

91 Exh. CalCCA-01C at 19.

having been "adopted" or "approved" by the Commission.

SCE treats the cost of its Energy Procurement & Management (EPM) organization (the equivalent to PG&E's ESA costs) and its collateral carrying costs separately.[92] It allocates EPM and collateral costs among its generation balancing accounts, and PCIA vintages, in different ways.[93] According to SCE, collateral costs are included in "Common" Costs that are allocated to the ERRA, NSGBA, and PABA balancing accounts according to the net revenue requirement in each account.[94] The portion allocated to PABA is then allocated to PCIA vintages based on the gross procurement costs associated with each vintage (*i.e.*, PCIA portfolio costs before netting out wholesale market value).[95] SCE allocates credit and collateral interest costs between PABA, ERRA, and NSGBA based on the authorized revenue requirements of each account.[96] And EPM costs are included in the Authorized Generation Base Revenue Requirement, *i.e.*, the fixed costs of generation as determined in a GRC, which is split between SCE's Legacy UOG and 2004-2009 PCIA vintages.[97, 98]

When asked to provide a citation to the Commission decisions or other authority addressing the allocation of common costs between SCE's balancing accounts, SCE referenced Advice Letter

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92 *Id*. at 18.

93 *Id*.

94 *Id*. (citing A.24-05-007, SCE response to CalCCA data requests 3.12 and 5.02).

95 *Id*. (citing A.24-05-007, SCE response to CalCCA data requests 3.11 and 5.01).

96 *See* AL 3914-E, pp. 4-5. *See also* Exh. CalCCA-01C at 19 (citing SCE response to CalCCA 3.13 and 3.14 (A.24-05-007)). Note that SCE allocates GHG carrying costs to PABA, ERRA, and NSGBA based on GHG costs in each account. Exh. CalCCA-01C at 19, footnote 45.

97 Exh. CalCCA-01C at 19 (citing to A.24-05-007, SCE response to CalCCA data request 3.16).

98 SDG&E also allocates its equivalent of ESA costs among PCIA vintages according to the GRC revenue requirement of its owned generation resources. SDG&E proposed in its 2025 ERRA Forecast to assign these costs entirely to the Non-Vintage PCIA subaccount. Exh. CalCCA-01C at 19, footnote 47.

3914-E establishing the PABA, approved by the Commission's Energy Division on May 3, 2019.[99] But nothing in Advice Letter 3914-E authorizes SCE's current approach to allocating **ESA-equivalent costs.** In fact, AL 3914-E does not so much as mention ESA or EPM costs—a fact PG&E concedes.[100] Rather, AL 3914-E authorizes SCE to allocate certain **non-ESA common costs** to PABA, ERRA and CAM based on the authorized revenue requirement, and allocate costs among PCIA vintages based on the revenue requirement associated with those vintages.[101] Thus, PG&E's assertion that its latest ESA cost allocation proposal aligns with SCE's *Commission-approved* methodology for allocating its equivalent of ESA costs[102] is inaccurate, because SCE's methodology for allocating EPM costs has not in fact been approved by the Commission. CalCCA had intended to raise this issue, and propose the same Version 1.0 proposal, in SCE's ERRA Forecast proceeding, but the Commission deemed this issue out of scope in that proceeding.[103]

Again, to the extent the Commission agrees it is worthwhile to align the IOUs' Common Cost allocation methodologies, it should consider those methodologies in a rulemaking or other consolidated proceeding, and not in multiple ERRA Forecast dockets with separate records. PG&E's repeated attempts (and failures) to accurately describe—let alone match—SCE's approach in this proceeding illustrates why.

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99 Exh. CalCCA-01C, Attachment B (SCE response to CalCCA discovery request 3.13).

100 Exh. CalCCA-02C (PG&E response to CalCCA discovery request 4.10, acknowledging SCE's AL 3914-E includes no mention of ESA costs or direction on how to allocate EPM costs, which are similar to PG&E's ESA costs.)

101 *Id*. (PG&E response to CalCCA discovery request 4.11).

102 Exh. PG&E-3 at 20.

103 A.24-05-007, *Assigned Commissioner's Scoping Memo and Ruling* (Aug. 14, 2024).

C. PG&E's Latest Allocation Proposal Would Exacerbate an Existing Cost Shift by Requiring Unbundled Customers to Cover Nearly 60% of Costs from Which They Do Not Benefit, Whereas CalCCA's Proposal Would Minimize That Cost Shift

Putting aside PG&E's inability to correctly characterize SCE's common cost allocation methodology, PG&E's allocation proposal (both Version 2.0 and Version 3.0) conflicts with Section 365.2 of the California Public Utilities Code because it would exacerbate an existing cost shift between bundled and unbundled customers. As Table 1 in PG&E's rebuttal testimony demonstrates, under its proposal, PG&E would allocate the vast majority of ESA costs—over 87%— to the PCIA.[104] PG&E confirmed that its EPP organization performs activities like bidding, scheduling, and/or dispatching resources not only for PCIA-eligible resources, but also for CAM resources and other resources, in addition to scheduling PG&E's bundled load in the CAISO market.[105] In other words, ESA costs relate to activities that go beyond the management of PCIA-portfolio resources.

PG&E's current ESA cost allocation methodology, which allocates costs across ERRA, PABA and CAM, implicitly recognizes that fact. In contrast, assigning nearly all ESA costs to the PCIA as PG&E proposes would require departed load customers to pay a proportional share of <u>all</u> ESA costs, ignoring the fact that a portion of those costs provide no benefit to departed load customers.[106] For example, to the extent PG&E incurs ESA costs to support new resource procurement for today's bundled customers, or incurs ESA costs to schedule bundled load into the

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[104] PG&E would allocate only a small portion of ESA costs to CAM, based on the UOG revenue requirements associated with the single UOG CAM facility. *See* Exh. CalCCA-02C (PG&E response to CalCCA discovery request 4.09b). And PG&E would allocate a similarly small portion of ESA costs—relating to PG&E's gas supply activities—to ERRA. Exh. PG&E-3 at 23. In 2025, the total ESA cost allocation to ERRA and CAM would be $11,927,000, whereas the total ESA cost allocation to the PCIA would be $80,866,000—approximately 87% of total ESA costs. Exh. PG&E-3 at 23.

[105] Exh. CalCCA-01C, Attachment B (PG&E's response to CalCCA data requests 1.28 and 1.34).

[106] *Id*. at 13.

CAISO market, unbundled customers (including those who departed bundled service many years ago) would be required to pay nearly 60% of those costs.[107] This would require unbundled customers to contribute to costs that were not incurred on their behalf, violating the ratepayer indifference principle established in California law.[108]

Unfortunately, PG&E's cost tracking processes are not set up in a manner that would allow the utility to perfectly delineate the Common Costs it incurs for PCIA, CAM, or ERRA-related activities, nor does PG&E track time spent administering contracts by PCIA vintage.[109] This inhibits the Commission's ability to exactly match cost allocation to cost-causing activities. In response to CalCCA discovery requests, PG&E confirmed it does not track time associated with ESA costs in a manner that would allow it to determine the percentage of ESA costs incurred on bundled customers' behalf, let alone allowing it to confirm that percentage is equal to bundled customers' load share of 36.7%.[110]

As such, the Commission should not aim to adopt an allocation methodology that matches cost allocation with load share (as PG&E seems to argue it should[111]) because it is not possible. More importantly, however, there is simply no evidence in the record to suggest that customers' load share bears a direct relationship to the drivers of PG&E's ESA cost. In fact, PG&E readily acknowledges that the costs of administering its energy supply portfolio "do not necessarily scale with load increases, and in some cases may increase with increased load departure,"[112]

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107 Exh. PG&E-3 at 23 (Table 1, demonstrating that departed load would pay 57.4% of total ESA costs in 2025 under PG&E's revised cost allocation proposal).

108 Cal. Pub. Util. Code §§ 365.2, 366.2.

109 Exh. CalCCA-01C at 14, Attachment B (PG&E's response to CalCCA discovery requests 1.19, 1.29 and 1.35).

110 Exh. CalCCA-02C (PG&E response to CalCCA data request 4.14).

111 Exh. PG&E-3 at 22.

112 Exh. CalCCA-02C (PG&E response to CalCCA data request 4.16).

emphasizing that allocating Common Costs in a manner that matches load share is neither logical nor equitable.

Absent more granular data that tracks ESA cost by resource, the most equitable approach to allocating ESA costs is to allocate those costs based on the total revenue requirements of the generation-related balancing accounts. That approach would allocate ESA costs based on the EPP group's main tasks (responding to procurement requirements; contracting the resources necessary to respond to those requirements; scheduling and bidding those resources at CAISO; and settling the resulting transactions) and would allocate ESA costs across balancing accounts and vintages based on which customers' behalf procurement activities are undertaken.

Indeed, PG&E's proposed methodology—which would allocate Common Costs to PABA and CAM vintages based on the UOG GRC revenue requirements associated with each vintage[113]—implicitly acknowledges the reasonableness of allocating Common Costs based on revenue requirements (as opposed to load share). However, PG&E never explains why the Commission should adopt an allocation methodology based only on the UOG GRC revenue requirement associated with each balancing account, as opposed to total revenue requirements. The only defense PG&E offers for that approach is that it mimics SCE's ESA-equivalent cost allocation methodology, which—as this brief describes above—the Commission has not approved.

As the Commission decides this issue, it should consider how establishing a policy in this case will impact future allocations of costs attributable only to bundled customers, and how PG&E's approach would violate State law prohibiting cost-shifts. Eliminating all cost shifting is not possible given the nature of the tasks and the fact PG&E does not track the customers on whose behalf those tasks are completed. However, CalCCA's gross revenue requirement methodology

113 *Id*. (PG&E response to CalCCA discovery request 4.07).

best minimizes cost shifts and better matches the costs of both existing resources *and* future resources to the customers to whom those resources will provide benefits.

D. PG&E's Latest Allocation Proposal Would Create a New Cost Shift That CalCCA's Proposed Methodology Avoids

The Common Cost allocation proposal PG&E describes in rebuttal testimony would not only result in the cost shift described above but would also unfairly shift costs away from PCIA-exempt customers. In response to a CalCCA discovery request, PG&E confirmed its PCIA-exempt customers represent 6.9% of PGE&'s total system forecast load.[114] Those customers would not pay for ESA costs allocated and recovered through PG&E's PCIA rates, they would only pay for ESA costs allocated to CAM.[115] Under PG&E's proposal, however, only 3.3%[116] of ESA costs would be allocated to CAM in 2025, because the allocation of costs to CAM would be based on the GRC revenue requirements of a <u>single</u> CAM facility—the Elkhorn UOG facility, which represents just [redacted] of PG&E's total CAM capacity.[117] The GRC revenue requirements of that facility ($38,372,000)[118] represent only 13% of the total 2025 CAM revenue requirement ($302,203,000) presented in PG&E's prepared testimony.[119] PCIA-exempt customers would pay approximately 6.9% of the CAM-allocated costs, or 0.2% of PG&E's total ESA costs.

In contrast, CalCCA's gross revenue requirement methodology would require that PCIA-exempt customers pay a more equitable share of ESA costs, because it would allocate ESA costs to CAM based on the revenue requirements associated with the entire CAM portfolio—not just a

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114 *Id*. (PG&E response to CalCCA discovery request 4.09).

115 *Id*. (PG&E response to CalCCA discovery request 4.09).

116 *See* Exh. PG&E-3 at 23, Table 1 ($3,045,000 allocated to CAM, divided by a total $92,793,000 in ESA costs in 2025, which equals 3.28%).

117 *See* Exh. PG&E-2C at 5-18 (Table 5-6).

118 PG&E Rebuttal Workpapers A.48 and A.51.

119 Exh. PG&E-2C at 9-4, Table 1.

single resource. This makes good sense because PG&E incurs ESA costs associated with its entire generation portfolio (including contracted resources), and not with just the subset of resources reflected in GRC revenue requirements. Under the gross revenue requirement methodology, 5.4% of ESA costs would be allocated to CAM and paid for by all customers subject to CAM charges. By adopting CalCCA's proposed allocation methodology, therefore, the Commission can avoid creating a new cost shift from PCIA-exempt customers.

E. CalCCA's Proposed Allocation Methodology Protects the Hypothetical "Last Remaining Bundled Customer"

PG&E argues its Common Cost allocation proposal is equitable because it would avoid leaving a hypothetical "last remaining bundled service customer" with millions of dollars in costs—an issue in which the Commission has shown concern.[120] PG&E ignores, however, that CalCCA's proposal would achieve the very same outcome. In fact, CalCCA's proposed Common Cost allocation methodology is nearly the same methodology PG&E initially proposed to address the potential overallocation of ESA costs to bundled customers.[121] Again, in its comments on the ALJ's Fixed Generation Cost ruling in PG&E's 2024 ERRA Forecast proceeding, PG&E described its Version 1.0 proposal—the gross revenue requirement methodology CalCCA proposes here—would "**eliminate the risk that bundled service customers bear a disproportionate share of [common] costs.**"[122] PG&E also stated the gross revenue requirement methodology is "**supported by statutory requirements to prevent cost shifting**, and those modifications to cost allocation and balancing account frameworks that were ordered by D.18-10-

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[120] Exh. PG&E-3 at 20.

[121] Exh. CalCCA-01C at 10.

[122] A.23-05-012, Pacific Gas and Electric Company's (U39 E) Response to Administrative Law Judge's Ruling Directing Parties to Comment Regarding Fixed Generation Costs at 6 (Aug. 16, 2023) (emphasis added).

019 and implemented by PG&E."[123]

Indeed, by allocating ESA costs based on the *gross* revenue requirements associated with PG&E's generation-related balancing accounts (and PABA vintages), PG&E can ensure bundled customers do not bear a disproportionate share of Common Costs as load continues to depart. That is because departing load would continue to pay for those costs via the PCIA (and CAM)—notwithstanding the market value of PG&E's PCIA portfolio.

F. The Commission Should Apply Any Modification to PG&E's Common Cost Allocation Methodology Prospectively

PG&E proposes not only to modify its Common Cost allocation methodology for the 2025 ERRA Forecast, but also requests the Commission adopt its proposed methodology *on a retroactive basis effective January 1, 2024*.[124] The Commission should reject PG&E's attempt to reach back to 2024 rates already embedded in tariffs PG&E must follow by law, and should implement any change to PG&E's Common Cost allocation methodology effective January 1, 2025.

As CalCCA witness Dickman explains, ERRA Forecast proceedings are designed to establish the forecasted ERRA and PCIA revenue requirement for the upcoming year.[125] That forecast is trued-up after the fact with actual results which are recorded to the PABA and ERRA balancing accounts such that customers are responsible for PG&E's actual, prudently incurred, procurement costs.[126] However, once the ERRA and PCIA revenue requirement forecasts are approved, the Commission does not allow PG&E to restate or recalculate those revenue

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123 *Id*. at 7 (emphasis added).

124 Exh. PG&E-2C at Chapter 10, page 10-11 to 10-12.

125 Exh. CalCCA-01C at 20.

126 *Id*.

requirements after the fact.[127] Doing so would violate the Commission's prohibition on retroactive ratemaking.[128]

PG&E itself recognized this fact in last year's ERRA Forecast proceeding when it opposed a proposal made by CalCCA witness Brian Shuey to change the accounting for banked RECs in years prior to the ERRA Forecast test year.[129] PG&E argued, "Mr. Shuey's proposal seeks to relitigate the adopted methodology for 2023 with a new proposal to be applied to both 2023 and 2024. While the methodology PG&E proposed in A.22-05-029 was not intended to be precedential, 2023 rates were established using that methodology and should not be adjusted in this proceeding."[130] The same argument applies directly to PG&E's attempt to relitigate the adopted methodology for allocating Common Costs in 2024.

PG&E defends its request to claw back 2024 authorized revenue requirements by pointing out that it initially raised the common cost allocation issue in the 2024 ERRA Forecast.[131] However, the Commission declined to consider PG&E's proposal in that case, and PG&E has since changed its recommended Common Cost allocation methodology more than once. PG&E never explains why the Commission can or should implement retroactively a methodology that PG&E never even advanced in last year's ERRA Forecast proceeding.

PG&E also argues "this Application concerns the true-up of 2024 costs" and suggests the Commission could retroactively adopt its proposed allocation methodology as a part of that true-

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127 *Id*.

128 *See The Ponderosa Telephone Co. v. Pub. Util. Com.*, 197 Cal. App. 4th 48, 63-64 (5th Dist. 2011) (citing *Pacific Tel. & Tel. Co. v. Public Util. Comn.*, 62 Cal. 2d 634, 650 (1965) for the proposition that a roll back of rates already approved by the Commission constitutes retroactive ratemaking).

129 Exh. CalCCA-01C at 20.

130 *Id*. at 20-21 (citing A.23-05-012, PG&E Rebuttal Testimony, page 19, lines 16-20).

131 *Id*. at 21; Exh. PG&E-02 at 24.

up.[132] The Commission should disregard PG&E's liberal use of the term "true-up." Again, the true-up that occurs in ERRA Forecast proceedings concerns the true-up of actual costs and revenues to those that were forecast in last year's Forecast proceeding, such that PG&E can timely address an under- or over-collection via next year's rates. The true-up is not a vehicle to reach back and unsettle prior year approved revenue requirements in order to reflect a new proposal made in the current year's proceeding. Any other interpretation of the true-up would introduce into these ERRA Forecast proceedings significant uncertainty regarding the magnitude of the true-up and its impact on rates. The Commission should decline to create that uncertainty and apply any new methodology adopted in this proceeding strictly on a going forward basis.

IV. UNCONTESTED ISSUES AND ISSUES TO BE ADDRESSED IN THE OCTOBER UPDATE

A. PG&E Should Apply Banked RECs Towards its Minimum Retained RPS Requirement in 2025 And Value Those Credits At the Forecast Adder

In recent ERRA Forecast proceedings, PG&E has forecast a shortfall in RECs required to meet its Minimum Retained RPS requirement, and in those proceedings, has proposed to use banked (surplus) RECs from prior years to meet the requirement while valuing the RECs it uses at the RPS Adder. In PG&E's prepared testimony this year, however, PG&E did not forecast a REC shortfall, and instead, projected RPS-eligible generation in excess of its compliance requirement.[133] PG&E deemed that surplus generation "Excess RPS" and proposed to assign Excess RPS volumes a zero-dollar value in PG&E's Indifference Amount calculation.[134] CalCCA objected to PG&E's "Excess RPS" proposal because it inappropriately invented a new category of RPS attributes not previously recognized by the Commission in its decisions establishing the PCIA

[132] Exh. PG&E-3 at 24.

[133] Exh. CalCCA-01C at 22.

[134] *Id*.

framework.[135]

PG&E's Excess RPS proposal, however, was mooted by PG&E's RPS sales following the filing of its prepared testimony. In its rebuttal testimony, PG&E explains:

> Subsequent to Prepared Testimony, PG&E executed sales agreements for 2025 RPS energy and RECs. As a result of such sales, as well as other applicable forecast assumption updates, PG&E's Fall Update will reflect a forecast RPS deficiency relative to PG&E's bundled service customers annual RPS imputed compliance requirement for 2025. Therefore, PG&E considers the issue of whether "Excess RECs" should be retained by PG&E or not as moot. Those 2025 volumes will now be sold and revenues from those sales will reduce the forecast 2025 Power Charge Indifference Adjustment (PCIA) revenue requirement.[136]

PG&E further explained that to meet the forecast 2025 Minimum Retained RPS requirement, PG&E anticipates using RECs generated (and banked) in 2018, and possibly in 2020.[137] In response to a CalCCA discovery request seeking to clarify PG&E's intended approach, PG&E confirmed it would value any 2018 or 2020 banked RECs that it uses at the 2025 Forecast RPS Adder.[138] This is consistent with its approach in prior ERRA Forecast proceedings and the Commission's decisions in those cases. Further, PG&E confirmed it would first use excess RECs generated and retained in 2018 until exhausted before using excess RECs generated and retained in 2020 (if necessary), consistent with the FIFO method directed by Ordering Paragraph 12 in D.23-12-022.[139]

While CalCCA continues to take the position that creating an "Excess RPS" category and

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[135] *Id*.

[136] Exh. PG&E-3 at 17.

[137] Exh. PG&E-3 at 17; *see* Exh. CalCCA-02C (PG&E response to CalCCA discovery request 4.03, indicating that PG&E anticipates using approximately [redacted] gigawatt-hours of excess RECs generated and retained in 2018).

[138] Exh. CalCCA-02C (PG&E response to CalCCA discovery request 4.01, 4.02).

[139] *Id*. (PG&E response to CalCCA discovery request 4.04).

valuing Excess RPS volumes at zero is not consistent with the Commission's PCIA framework, CalCCA agrees PG&E's Excess RPS proposal is moot to the extent PG&E no longer forecasts surplus RPS-eligible generation in 2025. Moreover, CalCCA does not object to PG&E's intended approach to addressing its forecast RPS deficiency in 2025 (as described in its rebuttal testimony and responses to CalCCA's discovery requests) and agrees that approach is consistent with past Commission decisions. This issue is therefore not disputed, and CalCCA looks forward to reviewing PG&E's updated Indifference Amount calculation in its Fall Update testimony.

B. PG&E Should Correct the Allocation of Sold RA and Unsold RA in the Indifference Amount Calculation

Per PG&E's Indifference Amount calculation in Table 10-9 of its testimony, PG&E reports a negative quantity Retained System RA from PCIA-eligible resources.[140] Negative Retained RA, however, does not make sense in the context of the PCIA, and when a negative quantity is applied to the RA Adder it would result in a charge, rather than a credit, to the PCIA for Retained RA.[141] CalCCA witness Dickman's further examination of PG&E's PCIA workpapers revealed the negative Retained RA is PG&E calculation is due to PG&E's treatment of forecasted sales of residual RA capacity and the remaining Unsold RA for 2025.[142]

To develop a forecast of residual RA sales and the expected amount of Unsold RA during 2025, PG&E first calculates the quantity of System RA needed for its bundled customer RA compliance. PG&E then compares that amount to the total, outage adjusted, net qualifying capacity (NQC) available from its resource portfolio, including its PCIA-eligible resources.[143] For months

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[140] PG&E-02C, Table 10-9, line 20 (excluding CTC and PPCP resources).

[141] Exh. CalCCA-01C at 32.

[142] *Id*. at 31.

[143] PG&E-2C at page 6-8 to 6-9.

that have a long system RA position, PG&E assumes some portion of the excess will remain unsold based on actual experience in the most recent four calendar quarters.[144] PG&E assumes the other portion of its excess RA position will be sold to third parties, and includes these residual RA sales in the Indifference Amount calculation as a reduction to the available System RA from PCIA resources and a revenue credit that reduces PCIA portfolio procurement costs.[145] Unsold RA is also reflected as a reduction to System RA in the Indifference Amount and is valued at $0.[146]

PCIA resources that provide System RA are counted in PG&E's portfolio when it calculates the RA position and resulting Sold and Unsold RA quantities.[147] However, many of those same resources also provide Local or Flexible RA capacity.[148] According to PG&E, when the RA from its PCIA-eligible generation portfolio is included in the Indifference Amount calculation, it is categorized as System, Local, or Flexible RA based on the type of RA the resource provides.[149] Pursuant to D.18-10-019, resources that provide System RA but also provide Local RA or Flexible RA are categorized as either Local RA or Flexible RA.[150]

Reducing only System RA for residual RA sales and Unsold RA creates a mismatch between the Sold and Unsold RA quantities and the available NQC in different RA categories.[151] In discovery PG&E confirmed that the result of this approach for 2024 results in a negative quantity for Retained System RA based on how PG&E's PCIA-eligible RA resource supply is split

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144 Exh. CalCCA-01C, Attachment B (PG&E's response to CalCCA data request 2.10).

145 PG&E-2C at 10-17 to 10-18.

146 Exh. CalCCA-01C at 31.

147 *Id*.

148 *Id*. at 31-32.

149 PG&E-2C at 10-17.

150 D.18-10-019 at 74.

151 Exh. CalCCA-01C at 32.

between System Local, and Flex RA.[152] Table 5 below quantifies the available RA as categorized in PG&E's PCIA and the resulting Retained, Sold, and Unsold RA by category.

Table 5: PG&E's Filed Retained, Sold, and Unsold RA Quantities (MW)

	Available RA	Unsold RA	Sold RA	Retained RA
Local NQC	[redacted]			3,779
Flex NQC	[redacted]			4,914
System NQC	[redacted]			(331)
	[redacted]			8,362

Again, negative Retained RA creates absurd results in the context of the PCIA. To correct this issue, CalCCA witness Dickman recommended the Commission direct PG&E to spread the forecasted Sold and Unsold RA between all of the RA categories rather than assign it all to System RA.[153] As Mr. Dickman explained, for purposes of the Indifference Amount forecast, projected Sold and Unsold RA volumes should be spread across the System, Local, and Flex RA based on the proportion of available RA by category.[154] The amount by RA category would then be allocated to PCIA vintages based on available RA in each vintage.[155] This approach would ensure a more accurate reflection of the utility's resource adequacy position in the PCIA and prevent the occurrence of negative Retained RA values.[156] Allocating Forecast Sold RA across RA categories and PCIA vintages is also consistent with D.19-10-001. When defining Forecast Sold RA, the Commission directed that revenue from sales that are not resource specific should be allocated *pro*

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152 *Id.*, Attachment B (PG&E's response to CalCCA data request 2.12).

153 *Id.* at 32-33.

154 *Id.* at 33.

155 *Id.*

156 *Id.*

rata based on the quantity of RA MW for each type of RA (System, Flexible, and Local) in each vintage.[157]

Table 6 below demonstrates the allocation of Sold and Unsold RA among RA categories based on the available RA in the 2025 Indifference Amount forecast.

Table 6: Allocation of Sold and Unsold RA (MW)

	Available RA	Unsold RA	Sold RA	Retained RA
Local NQC	[redacted]	[redacted]	[redacted]	3,080
Flex NQC	[redacted]	[redacted]	[redacted]	4,005
System NQC	[redacted]	[redacted]	[redacted]	1,277
	[redacted]	[redacted]	[redacted]	8,362

After indicating that it would support proportionally allocating residual RA sales and Unsold RA forecast volumes across the three RA benchmark types in response to a CalCCA discovery request,[158] PG&E confirmed it agrees with CalCCA witness Dickman's recommendation in its rebuttal testimony.[159] PG&E stated it "intends to make that change in its Fall Update forecast."[160] PG&E expects this adjustment will decrease its PCIA revenue requirement presented in its prepared testimony by $68.6 million;[161] however, the final impact of the adjustment for 2025 will depend on updated quantities of available RA, Sold RA and Unsold RA in PG&E's Fall Update. This issue is not disputed, and CalCCA looks forward to reviewing PG&E's agreed adjustment in its Fall Update testimony.

157 D.19-10-001 at 32.

158 Exh. CalCCA-01C, Attachment B (PG&E's response to CalCCA data request 2.12).

159 Exh. PG&E-3 at 26.

160 *Id.*

161 *Id.*

C. PG&E Should Correct an Error Related to the Gain on Sale of its San Francisco General Office

In D.21-08-027, the Commission authorized PG&E to credit customers the gain on the sale of its SFGO headquarters over a five-year period from 2022 through 2026.[162] Because a portion of the costs to own and operate SFGO is allocated to PG&E's electric generation revenue requirement and included in the GRC-related electric generation costs recovered through PCIA rates, a portion of the benefits related to the sale are also allocated to electric generation and included as a credit to the Indifference Amount.[163]

PG&E's Application includes a $13.3 million credit for the electric generation portion of the net gain on sale of SFGO, reflecting year 4 of the amortization of the gain.[164] CalCCA witness Dickman notes that PG&E used an incorrect allocation factor to determine the electric generation portion of the gain for 2025.[165] PG&E applied a generation allocation factor of 24.24% to the amortization credit rather than the correct 39.45% generation allocation factor.[166] Applying the correct generation allocation factor results in an amortization credit of $21.6 million for electric generation during 2025.[167]

PG&E confirmed this error in response to a CalCCA discovery request, provided the correct calculations, and agreed to correct the amortization amount in the Fall Update.[168] And in its rebuttal testimony, PG&E confirms it agrees with Mr. Dickman's recommended adjustment,

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162 Exh. CalCCA-01C at 34.

163 *Id*.

164 Exh. PG&E-2C at Chapter 10, Table 10-1.

165 Exh. CalCCA-01C at 34.

166 *Id*.

167 *Id*.

168 *Id*., Attachment B (PG&E's response to CalCCA data request 2.09).

and commits to updating its calculation to reflect the correct generation allocation factor in its Fall Update Forecast.[169] Correcting the error reduces the 2025 Indifference Amount by $8.0 million.[170] Correcting the same error should also reduce ERRA and CAM revenue requirements by a combined $0.3 million, for a total correction of $8.3 million.[171] This issue is not disputed and CalCCA looks forward to reviewing PG&E's agreed adjustment in its Fall Update testimony.

V. CONCLUSION

For the foregoing reasons, CalCCA requests that the Commission:

- Adopt CalCCA's recommended Common Cost allocation methodology, which allocates Common Costs across the ERRA, CAM and PABA based on the gross revenue requirement in each category, and to PCIA vintages based on the gross revenue requirement by vintage;
- Apply any new Common Cost allocation methodology it adopts in this proceeding starting January 1, 2025;
- Approve PG&E's proposal to use 2018 and, if necessary, 2020 banked RECs on a FIFO basis to meet its 2025 Minimum Retained RPS requirement, and to value the RECs it uses at the 2025 Forecast RPS Adder;
- Adjust PG&E's PCIA revenue requirement to (1) reflect an agreed adjustment that spreads RA projected to be Sold or Unsold across System, Local and Flex RA categories based on the proportion of available RA by category, and (2) reflect an agreed adjustment related to an error in the amount PG&E included as the amortization of the gain on sale of PG&E's SFGO headquarters; and
- Apply the legal standard discussed in this Opening Brief to the October Update.

CalCCA reserves its right to modify these recommendations based on updated information presented in PG&E's Fall Update, and to address other issues raised therein, via comments on the October Update or any further process the Commission might adopt.

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169 Exh. PG&E-3 at 26.

170 Exh. CalCCA-01C at 34; *see also* Exh. PG&E-02C at 26.

171 Exh. CalCCA-01C at 34.

Dated: October 21, 2024

Respectfully submitted,

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PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

Date **Agenda ID #23020**
Ratesetting

TO PARTIES OF RECORD IN RULEMAKING 23-10-011:

This is the proposed decision of Administrative Law Judge Debbie Chiv. Until and unless the Commission hears the item and votes to approve it, the proposed decision has no legal effect. This item may be heard, at the earliest, at the Commission’s 12/5/2024 Business Meeting. To confirm when the item will be heard, please see the Business Meeting agenda, which is posted on the Commission’s website 10 days before each Business Meeting.

Parties of record may file comments on the proposed decision as provided in Rule 14.3 of the Commission’s Rules of Practice and Procedure.

The Commission may hold a Ratesetting Deliberative Meeting to consider this item in closed session in advance of the Business Meeting at which the item will be heard. In such event, notice of the Ratesetting Deliberative Meeting will appear in the Daily Calendar, which is posted on the Commission’s website. If a Ratesetting Deliberative Meeting is scheduled, *ex parte* communications are prohibited pursuant to Rule 8.2(c)(4).

/s/ MICHELLE COOKE
Michelle Cooke
Chief Administrative Law Judge

MLC:smt

Attachment

Decision **PROPOSED DECISION OF ALJ CHIV** **(Mailed 10/29/2024)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	Rulemaking 23-10-011

DECISION ON TRACK 2 ISSUES

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DECISION ON TRACK 2 ISSUES

Summary

This decision addresses issues scoped as Track 2 of this proceeding, including adopting modifications to the central procurement entity (CPE) framework, such as eliminating the non-compensated self-show option of the CPE framework and locking in CPE allocations to load-serving entities one year earlier.

This proceeding remains open.

1. Procedural History

A Scoping Memo and Ruling (Scoping Memo) for this proceeding was issued on December 18, 2023. The Scoping Memo set forth a scope of issues divided into three tracks (Track 1, 2, and 3). Track 1 issues were addressed in Decision (D.) 24-06-004, issued by the Commission on June 26, 2024. Track 2 issues will be considered in this decision, including issues related to the central procurement entity (CPE) framework and the revised Loss of Load Expectation (LOLE) study and Planning Reserve Margin (PRM) for the 2026 and 2027 Resource Adequacy (RA) compliance years.

On March 15, 2024, Energy Division issued its Proposed Inputs and Assumptions, which was attached to an Administrative Law Judge's (ALJ) ruling on March 18, 2024. Energy Division issued a report on the CPE framework on May 31, 2024, titled Report on the 2021-2023 Central Procurement Entity Framework, and issued a revised version of the report on June 4, 2023. On June 5, 2024, an ALJ ruling attached Energy Division's report.

Proposals on Track 2 issues were filed on June 14, 2024 by: American Clean Power – California (ACP-CA); Alliance for Retail Energy Markets (AReM); California Community Choice Association (CalCCA); California Environmental

Justice Alliance (CEJA) and Sierra Club (collectively, CEJA/Sierra Club); California Energy Storage Alliance (CESA); Middle River Power, LLC (MRP); Pacific Gas and Electric Company (PG&E); Southern California Edison Company (SCE); Vistra Corp. (Vistra); and Western Power Trading Forum (WPTF).

Energy Division issued the LOLE Study for 2026 (including Slice of Day Tool Analysis) (LOLE study) on July 19, 2024. On July 22, 2024, the ALJ's ruling attached Energy Division's LOLE study. Workshops on Track 2 proposals and the LOLE study were held on July 25 and July 26, 2024.

Opening comments on Track 2 proposals were filed on August 9, 2024 by: ACP-CA; AReM; California Independent System Operator (CAISO); CalCCA; Public Advocates Office at the Public Utilities Commission (Cal Advocates); California Wind Energy Association (CalWEA); Calpine Corporation (Calpine); CEJA/Sierra Club; CESA; California Efficiency + Demand Management Council (Council) and OhmConnect, Inc. (OhmConnect) (collectively, Council/OhmConnect); Department of Market Monitoring of CAISO (DMM), Leapfrog Power, Inc. (Leap); Microsoft Corporation (Microsoft); MRP; New Leaf Energy, Inc. (New Leaf Energy); NextEra Energy Resources, LLC (NEER); Protect Our Communities Foundation (PCF); PG&E; San Diego Gas & Electric Company (SDG&E); SCE; and WPTF.

Reply comments on Track 2 proposals were filed on August 23, 2024 by: AReM; CalCCA; Cal Advocates; CEJA/Sierra Club; Central Coast Community Energy (3CE); CESA; Council/OhmConnect; Large-Scale Solar Association (LSA); PCF; PG&E; REV Renewables, LLC (REV); and SCE. MRP was granted leave to late-file reply comments on August 26, 2024.

On August 30, 2024, Energy Division issued Appendix A: Revised Slice Of Day (SOD) Tool Analysis and the SOD calibration tool. An ALJ's ruling attached Appendix A.

On September 9, opening comments on the revised SOD PRM calibration tool were filed by: AReM, Ava Community Energy (Ava), CAISO, Cal Advocates, CalCCA, Calpine, CEJA/Sierra Club, California Municipal Utilities Association (CMUA), MRP, PCF, PG&E, SCE, SDG&E, and WPTF. On September 16, reply comments on the revised SOD PRM calibration tool were filed by ACP-CA, AReM, CAISO, Cal Advocates, CalCCA, Microsoft, MRP, PCF, PG&E, SCE, SDG&E, Shell Energy North America (US), L.P. (Shell Energy), and WPTF.

All rulings by the assigned Commissioner and the assigned Administrative Law Judge are affirmed. Any pending motions are denied.

2. Submission Date

This matter was submitted on September 16, 2024 upon the submission of reply comments on the revised SOD PRM calibration tool.

3. Issues Before the Commission

The scope of Track 2, as adopted in the December 18, 2023 Scoping Memo, is summarized below:

1. Structural modifications and/or refinements to the CPE framework. Energy Division will issue a report on the CPE framework in the 1st Quarter of 2024, as directed by Decision (D.) 22-03-034. The Commission will consider proposals on structural modifications and/or refinements to the CPE framework.

2. LOLE Study and PRM. The Commission will consider modifications to the PRM for compliance years 2026 and 2027, including the results of Energy Division's annual LOLE study. The Commission will consider party input in

developing the study inputs and assumptions, including consideration of Path 26 and the treatment of Diablo Canyon Nuclear Generating Facility pending the outcome of Rulemaking (R.) 23-01-007.

3. Coordination with the Integrated Resource Planning (IRP) Proceeding. This will include the appropriate PRM requirements for short-term planning compared with the longer timeframe for the IRP proceeding, and coordination with the IRP proceeding's development of a programmatic approach to procurement being considered in the IRP proceeding as the Reliable and Clean Power Procurement Program (RCPPP).

On June 4, 2024, an ALJ's ruling was issued that stated that based on the adopted schedule for RCPPP development in the IRP proceeding, "it is necessary to defer consideration of the Track 2 topic 'Coordination with the IRP Proceeding' until after the RCPPP proposal has been considered in the IRP proceeding."[1] As such, Issue 3 above has been deferred until after the Commission issues a decision on the RCPPP proposal in R.20-05-033.

4. Discussion

4.1. 2026 LOLE Study and PRM Process

On July 19, 2024, Energy Division issued its 2026 LOLE study that establishes a PRM and supports the translation of resource needs in the SOD framework.[2] Compared to previous years, Energy Division's LOLE analysis utilized the California Energy Commission's (CEC) Integrated Energy Policy Report (IEPR) California Energy Demand Forecast managed peak, rather than the consumption peak.

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1 ALJ's Ruling Deferring Track 2 Issue on Coordination with the Integrated Resource Planning Proceeding, issued June 4, 2024, at 2.

2 Energy Division's 2026 LOLE Study, July 19, 2024, at 4.

Energy Division states that after extensive analysis, it determined that the 2023 IEPR CAISO coincident managed peak forecast appeared more consistent with historical trends than the consumption forecast. Energy Division determined that "[t]he 2023 IEPR, more so than previous years, reflects a large gap between the CAISO coincident consumption and managed peaks largely driven by different hourly profiles of consumption demand resulting from the different demand models used for the LOLE study and the IEPR."[3] Therefore, "[b]y tuning the median managed peak in the LOLE model to match the IEPR managed peak, staff confirmed that the model met the target reliability of 1 day in 10 years (0.1 LOLE) using the updated Baseline set of resources and evening peak hours CAISO simultaneous imports constrained to 2,500 MW rather than the prior assumption of 4,000 MW." In the study, Energy Division Staff stated that "[t]he results of this study show that with the baseline including existing resources and expected resource additions based on LSE contracting and development milestones, RA obligations can be met while allowing for some uncertainty or delay in resource development."[4]

Energy Division then implemented the resource portfolio from the LOLE study in the SOD PRM tool and calculated the required PRM in all 12 months. After calculating initial PRMs, Staff performed stress tests on varying levels of PRM needed to meet the target reliability level. Given the results of this analysis, Energy Division proposed a 18.5 percent PRM on top of the 2023 IEPR CAISO coincident managed peak demand forecast for all 12 months.

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[3] *Id.*

[4] *Id.* at 5.

On August 30, 2024, Energy Division issued a revised SOD tool analysis, titled Appendix A to Loss of Load Expectation Study for 2026: Slice of Day Tool Analysis (revised analysis). In the revised analysis, Energy Division states that "Staff identified errors in exceedance calculations, and in accounting for storage charging in the SOD tool. To resolve these errors Staff changed the objective function in the SOD tool for storage dispatch, updated the exceedance values and recalculated PRM levels based on the LOLE study."[5] Energy Division further states that "Staff recalculated both the SOD equivalent of the initial LOLE study (which was not rerun) then based on those initial LOLE SOD results, Staff redid the stress tests (including a revised SERVM LOLE run) to determine the required PRM values in each month."[6] Energy Division notes that the underlying LOLE study is unchanged.

Based on the revised analysis, Staff recommends adopting a 26.5 percent PRM on top of the CAISO coincident managed peak demand forecast in months January – May, and a 23.5 percent PRM in June – December. Energy Division states that the underlying resource fleet remains sufficient to meet reliability targets with the baseline set of resources only, with no additional generic resources added.

4.1.1. Comments on Energy Division's Analysis

The below summary of comments primarily focus on Energy Division's revised SOD PRM calibration results.

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[5] Appendix A to Loss of Load Expectation Study for 2026: Revised Slice of Day Tool Analysis (Appendix A to LOLE Study), at 2.

[6] *Id*.

CAISO, Calpine, MRP, and WPTF support the updated 23.5 percent and 26.5 percent PRM.[7] CAISO states that the updated PRM reflects PRM levels required to meet a 0.1 LOLE across the year and better align with the 0.1 LOLE target in the IRP proceeding.

Numerous parties oppose adopting the 23.5 percent and 26.5 percent PRM, including AReM, Ava, CalCCA, Cal Advocates, CEJA/Sierra Club, PG&E, PCF, SCE, and Shell Energy.[8] These parties generally state that the updated PRM is significantly higher than the 17 percent PRM in 2025 (and the PRM from the initial analysis), is not adequately justified by Energy Division's revised analysis, and will likely have downstream impacts that result in substantially higher costs to ratepayers and higher market prices as LSEs need to procure more resources to meet these requirements.

SCE states that the revised results indicate there are serious design or translation flaws in the modeling.[9] SCE identifies that the CAISO load profiles in the revised analysis do not appear to match the latest 2023 IEPR planning forecast and that several categories of resources in the revised analysis are questionable, such as including more combined cycle net qualifying capacity (NQC) than the total of all CAISO combined cycle plants. PG&E expresses concern about the demand response (DR) value that is significantly higher than

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[7] CAISO Comments on Appendix A to LOLE Study at 2, Calpine Comments on Appendix A to LOLE Study at 1, MRP Comments on Appendix A to LOLE Study at 2, WPTF Comments on Appendix A to LOLE Study at 2.

[8] AReM Comments on Appendix A to LOLE Study at 2, Ava Comments on Appendix A to LOLE Study at 2, Cal Advocates Comments on Appendix A to LOLE Study at 1, CalCCA Comments on Appendix A to LOLE Study at 8, CEJA/Sierra Club Comments on Appendix A to LOLE Study at 1, SCE Comments on Appendix A to LOLE Study at 2, PCF Comments on Appendix A to LOLE Study at 3, PG&E Reply Comments on Appendix A to LOLE Study at 2, Shell Energy Reply Comments on Appendix A to LOLE Study at 3.

[9] SCE Comments on Appendix A to LOLE Study at 6.

amounts used in prior studies and a lack of transparency regarding what resources are being used in the SOD tool.[10] CalCCA observes that the load shapes appear to have peaks shifted later in the day relative to the actual load shapes observed at CAISO, and that forced outages rates of storage and thermal generators are uncertain and may be too high in SERVM.[11] CalCCA, Cal Advocates, CEJA/Sierra Club, and SCE express concern that calibrating LOLE by adding blocks of load may have material impacts in the SOD framework.[12] Other parties, such an CEJA/Sierra Club, PCF, and Microsoft, express concern with artificially limiting the available imports in the translation, which appears to have artificially increased the PRM.[13]

AReM, Cal Advocates, CalCCA, and MRP seek an explanation of why two PRMs are needed, why the results for February were anomalous, and why a LOLE higher than 0.1 was targeted.[14] MRP and Cal Advocates also seek an explanation as to why the revised SOD values are derived not from the peak hour but from the most constrained hour in each month. CMUA states that the updated PRM does not account for factors other than the LOLE study, such as

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[10] PG&E Comments on Appendix A to LOLE Study at 2.

[11] CalCCA Comments on Appendix A to LOLE Study at 8.

[12] Cal Advocates Comments on Appendix A to LOLE Study at 4, CalCCA Comments on Track 2 Proposals, CEJA/Sierra Club Comments on Appendix A to LOLE at 1, SCE Comments on Appendix A to LOLE Study at 6.

[13] CEJA/Sierra Club Comments on Appendix A to LOLE Study at 1, PCF Comments on Appendix A to LOLE Study at 4, Microsoft Reply Comments on Appendix A to LOLE Study at 7.

[14] AReM Comments on Appendix A to LOLE Study at 2, CalCCA Reply Comments on Appendix A to LOLE Study at 4, MRP Comments on Appendix A to LOLE Study at 4.

affordability or feasibility, and that it may not be practical for non-Commission jurisdictional LSEs to adopt the PRM evenly.[15]

Numerous parties recommend deferring adoption of the 2026 PRM until further analysis can be completed and the PRM results can be vetted, including ACP-CA, AReM, CalCCA, Cal Advocates, Microsoft, PG&E, and SCE.[16] Some parties recommend considering the 2026 PRM in Track 3, while CalCCA recommends a decision in March 2025. CAISO, MRP, and WPTF support the requests for additional time to review the LOLE study and impacts, with WPTF and MRP recommending that a decision on the 2026 PRM still be issued in November 2024.[17] 3CE recommends retaining the current 17 percent PRM and not adopting a 2026 PRM until after the SOD framework has been implemented.[18]

4.1.2. Discussion

In D.22-06-050, the Commission adopted a minimum 17 percent PRM for the 2024 RA year. In D.23-06-029, the Commission adopted a 17 percent PRM for 2025, stating that "[g]iven the realities of available RA supply and persistent delays in development projects, it is prudent to retain the status quo 17 percent PRM for the 2024 and 2025 RA years. Increasing the PRM without greater

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[15] CMUA Comments on Appendix A to LOLE Study at 4.

[16] ACP-CA Comments on Appendix A to LOLE Study at 1, AReM Comments on Appendix A to LOLE Study at 2, CalCCA Comments on Appendix A to LOLE Study at 8, Cal Advocates Comments on Appendix A to LOLE Study at 4, Microsoft Reply Comments on Appendix A to LOLE Study at 7, PG&E Comments on Appendix A to LOLE Study at 2, SCE Comments on Appendix A to LOLE Study at 2.

[17] CAISO Reply Comments on Appendix A to LOLE Study at 3, MRP Reply Comments on Appendix A to LOLE Study at 5, WPTF Reply Comments on Appendix A to LOLE Study at 1.

[18] 3CE Reply Comments on Track 2 Proposals at 2.

certainty about installed RA resources for 2024 and 2025 is not appropriate at this time."[19] The decision further stated that "[t]he Commission will continue to monitor market conditions and impacts of the adopted PRM framework and will reevaluate the PRM requirements for the 2026 RA year in 2024."[20]

A broad range of parties recommend further analysis and vetting of Energy Division's revised analysis and raise numerous potential issues and errors with the revised analysis. The majority of parties recommend deferring adoption of the 2026 PRM to Track 3 of this proceeding, and seek additional data and information regarding the inputs used in the SOD tool.

The Commission agrees that additional vetting and further analysis of the issues raised by parties is needed. Energy Division is authorized to undertake a further revision of the 2026 PRM analysis to correct identified errors raised in comments, and distribute it to the service list in this proceeding in early December 2024. Following the release of the revised PRM analysis, Energy Division will conduct workshops to explain the analysis and supporting data. Energy Division may solicit informal comments on the analysis and parties will have an opportunity to submit formal comments. Following that process, the Commission will consider the revised PRM analysis in Track 3 of this proceeding.

Lastly, we note that some parties appear to misunderstand the definition and use of the LOLE metric and the mechanisms of the stress test. To enhance learnings of these concepts, Energy Division Staff should include additional clarifications in future LOLE reports.

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[19] D.23-06-029 at Finding of Fact 4.

[20] *Id*. at 25.

4.2. Additional LOLE and PRM Proposals

MRP recommends adopting a standard annual process to develop the PRM for the upcoming compliance year.[21] The proposed process would include Energy Division working with parties to develop inputs and assumptions for the LOLE studies, publication of a preliminary and final LOLE study with an opportunity to comment on each, and submission of proposals based on the final study results.

WPTF proposes adopting a 0.1 LOLE as the reliability standard in the RA program, as also used for IRP modeling.[22] WPTF also recommends specifying the stress test that Energy Division will be conducting as part of the LOLE study to establish the 2027 PRM. WPTF recommends that a regular LOLE study and PRM development process be established, including development of inputs and assumptions for each study and an opportunity to submit alternative LOLE studies.

AReM recommends a process to set a single PRM, as outlined in WPTF's Track 1 PRM proposal.[23] AReM states that the process is comparable to Energy Division Staff's Stress Test 3[24] and notes that if the process leads to an infeasible solution (i.e., greater capacity need in the peak month than can be supplied by available resources), AReM agrees with Energy Division's recommendation for a

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21 MRP Track 2 Proposals at 18.

22 WPTF Track 2 Proposal at 2.

23 AReM Track 2 Proposal at 7.

24 Energy Division, Slice of Day – Load Forecast Process Update and Loss of Load Studies Translation for RA proceeding Update, October 6, 2022, www.cpuc.ca.gov/-/media/cpucwebsite/divisions/energydivision/documents/resource-adequacy-homepage/resource-adequacycompliance-materials/resourceadequacy-history/10-6-2022-wrap-up/workshop-10_energydivision_221006.pdf.

"optional stress test" to set two PRMs, one for the peak month and one for other months.

Vistra recommends adopting a seasonal PRM for peak months and a different PRM value for non-peak months based on recurring probabilistic annual LOLE to ensure accurate assumptions for forced outages.[25] Vistra proposes that seasonal PRMs be updated beginning in 2026 by leveraging the LOLE studies and stress tests and that Energy Division update an annual LOLE study each February beginning in 2025 and every year after. Vistra also recommends that the LOLE study incorporate advanced notice and short notice forced outages to ensure that months with a possibility of unforeseen advanced notice forced outages are incorporated into generation availability assumptions. Vistra believes advanced notice forced outages are not reflected in the Generator Availability Data System (GADS) forced outage rates used in the current LOLE inputs and assumptions.

ACP-CA recommends aligning the SOD framework with probabilistic PRM calibration (as it previously proposed in Track 1).[26] ACP-CA recommends revisiting resource counting and accreditation for wind and solar resources to align with probabilistic modeling methods. ACP-CA contends that resource accreditation should align with expected contributions of a resource during critical reliability periods across a range of conditions and more sophisticated weather modeling programs should be evaluated to understand patterns outside the state. ACP-CA states that the current exceedance methodology approximates

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[25] Vistra Track 2 Proposal at 4.

[26] ACP-CA Track 2 Proposal at 4.

this result but does not reflect expected values during critical periods, which is problematic for resources in developing regions without operations data.

4.2.1. Comments on Proposals

Several parties support a regular schedule for LOLE studies and PRM updates with stakeholder participation, including CAISO, CalCCA, SCE, SDG&E, PG&E, and WPTF.[27] CAISO states that while an annual LOLE study would be ideal, a schedule that balances the benefits of updated inputs with staff resource demands should be considered. SDG&E states that a standard process would give certainty to LSEs and the market and allow the LOLE study/PRM to incorporate market changes over time. CEJA/Sierra Club oppose locking in an annual LOLE process before evaluating the proper reliability metric.[28]

SCE supports moving from a single PRM to seasonal, monthly, or peak/non-peak month PRMs and states that Energy Division should conduct more granular analyses to determine the best PRMs.[29] SCE supports adopting the Natural Resources Defense Council's LOLE Informed Intermittent Resource Counting proposal for LOLE modeling which would reduce errors, fairly compensate resources, and provide certainty in counting rules. CalCCA supports a single, annual PRM until the study methodology is sufficient to evaluate monthly or seasonal PRMs.[30] CalCCA states that the current methodology lacks variability that would warrant monthly or seasonal variation,

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27 CAISO Comments on Track 2 Proposals at 3, CalCCA Reply Comments on Track 2 Proposals at 3, SCE Comments on Track 2 Proposals at 6, SDG&E Comments on Track 2 Proposals at 2, PG&E Reply Comments on Appendix A to LOLE Study at 5, WPTF Comments on Track 2 Proposals at 4.

28 CEJA/Sierra Club Comments on Track 2 Proposals at 18.

29 SCE Comments on Track 2 Proposals at 6.

30 CalCCA Comments on Track 2 Proposals at 5.

as compared to the annual PRM. Microsoft supports Vistra's proposal and agrees that Energy Division should refine modeling to support seasonal PRMs.[31]

CAISO, MRP, Microsoft, and SDG&E support adopting a 0.1 LOLE reliability target for the RA program, as it is a general industry standard and can better align the RA requirements with the IRP proceeding.[32] CAISO recommends stress testing the PRM to ensure it meets a 0.1 LOLE across the year and to adopt stress testing as part of the PRM-setting process. WPTF comments that monthly stress tests should be conducted for future LOLE studies, as this can identify month-specific PRMs, can be used as a starting point for seasonal PRMs, and can identify a single PRM that achieves 0.1 LOLE reliability.[33]

Cal Advocates argues that there is no reason to formally adopt the 0.1 LOLE standard since the RA program already targets that standard and adoption may make the 0.1 LOLE standard binding, hampering the Commission's ability to adjust RA requirements and the PRM as issues arise.[34] Cal Advocates points to recent examples where the Commission declined to adopt a PRM based on the 0.1 LOLE study or when the Commission extended the effective PRM program. CalCCA states that while the industry definition of a reliable system is one that meets a 0.1 LOLE, the focus on reliability should not lose sight of implications on affordability.[35]

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31 Microsoft Comments on Track 2 Proposals at 5.

32 CAISO Comments on Track 2 Proposals at 2, Microsoft Comments on Track 2 Proposals at 2, MRP Comments on Track 2 Proposals at 6, SDG&E Comments on Track 2 Proposals at 4.

33 WPTF Comments on Track 2 Proposals at 3.

34 Cal Advocates Reply Comments on Track 2 Proposals at 2.

35 CalCCA Comments on Track 2 Proposals at 4.

CEJA/Sierra Club oppose a 0.1 LOLE standard and recommend analyzing a reliability definition based on loss of load hours (LOLH) and unserved energy.[36] CEJA/Sierra Club state that there is no consistent way to apply the 0.1 LOLE standard, though it is widely used, and that other methods for defining the 1-in-10 standard is one day every ten years, which translates into 2.4 hours of outage a year, or based on the examination of unserved energy. Microsoft agrees that parties would benefit from understanding the volumetric effect of outages using a LOLH metric.[37] SDG&E opposes a 2.4 hours per year relaxed standard as leading to decreased reliability because it would be a lower standard that would require fewer resources to be procured.[38] SDG&E points out that the study cited by CEJA/Sierra Club to conclude the 2.4 hours per year would result in a small reliability impact was from 2011 and the reliability challenges facing the grid have changed significantly.

CalWEA and PG&E support ACP-CA's proposal to remove the exceedance step in developing QC values for wind and solar.[39] CalWEA states that ACP-CA's analysis shows how translation of historical benchmarks into exceedance values arbitrarily drives overcounting and undercounting of solar values and undercounting of wind values. PG&E supports using the worst day benchmark and removing the exceedance step but notes that exceedance can still be used in development of the worst day benchmark, which would provide greater benchmark flexibility. PG&E supports further exploration of the methodologies.

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36 CEJA/Sierra Club Comments on Track 2 Proposals at 15.

37 Microsoft Comments on Track 2 Proposals at 9.

38 SDG&E Comments on Track 2 Proposals at 4.

39 CalWEA Comments on Track 2 Proposals at 1, PG&E Reply Comments on Track 2 Proposals at 9.

LSA is open to considering elimination of the exceedance step but states that the worst day approach must be equally transparent so that resources can determine what their RA value will be.[40] MRP is concerned that removing the exceedance step may lead to volatile and unreliable RA values but agrees that the methodology should be revisited.[41]

SCE supports aligning the process for RA resource counting with IRP and recommends moving the resource profile process to the IRP proceeding to align RA accreditation with capacity profiles used in the IRP and SERVM LOLE modeling.[42] SCE states that the advantages of this include consolidating focus to a single set of resource profiles and the availability of funding for third-party vendor IRP work. CalCCA supports consistency between data used in SERVM modeling, the SOD PRM translation, and resource accreditation.[43]

4.2.2. Discussion

The Commission highlights that the data gathering and reconciliation process for the inputs and assumptions that underlie the LOLE study is very time-consuming and resource intensive. The Commission therefore determines that it is not feasible to run an updated LOLE study each year. It is more realistic and reasonable for Energy Division Staff to update an RA LOLE study every two years. Accordingly, Energy Division is authorized to update the LOLE study every two years for consideration in the RA proceeding.

The Commission recognizes that a schedule for developing and discussing the LOLE study would be beneficial to stakeholders for understanding the LOLE

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[40] LSA Reply Comments on Track 2 Proposals at 2.

[41] MRP Reply Comments on Track 2 Proposals at 5.

[42] SCE Comments on Track 2 Proposals at 6.

[43] CalCCA Reply Comments on Track 2 Proposals at 8.

study inputs and process. We note, however, that any timeline must revolve around the availability of data inputs, notably including any revised IEPR data which is typically published in February of each year. Ahead of its expected biannual RA LOLE study, Energy Division is encouraged to develop and distribute a schedule that provides for necessary updates of data in the LOLE model, publication of an inputs and assumptions document, processing of inputs and assumptions into the SERVM model, completion of the LOLE study and stress tests, and opportunity for party comments.

As noted above, data gathering and reconciliation for the LOLE modeling process is a time-intensive, significant undertaking for Commission Staff. We underscore that Commission Staff is gaining experience as to how long the data development and modeling process will take for the new SOD framework, and we appreciate parties' patience as Staff develops and refines the modeling timelines.

The Commission sees merit in modifying the QC values for wind and solar resources using SERVM weather profiles, rather than using exceedance profiles, as this would better align SOD RA values with how SERVM stochastic datasets are used in the RA LOLE studies. However, we find that there is insufficient record at this time to consider this change and that more analysis is needed. In D.24-06-004, the Commission determined that "the exceedance levels for wind and solar resources will be adjusted to monthly levels, with the next update to occur in 2024 and subsequent updates every three years thereafter."[44] As such, the current exceedance levels for wind and solar resources have been locked in for three years. The Commission authorizes Energy Division to conduct an

[44] D.24-06-004 at Ordering Paragraph 8.

analysis comparing exceedance profiles for wind and solar resource against SERVM weather profiles to be considered in Phase 3 of this proceeding.

Regarding the 0.1 LOLE reliability standard, the Commission notes that Assembly Bill 2368 was recently passed, which provides that the Commission shall determine the most efficient and equitable means to "[e]nsuring that the resource adequacy program can reasonably maintain a standard measure of reliability, such as a one-day-in-10-year loss-of-load expectation or a similarly robust reliability metric adopted by the commission, and use it for planning purposes."[45] We agree with parties that state that a 0.1 LOLE reliability target is the general industry standard and use of the standard can better align the RA requirements with the IRP program. The 0.1 LOLE reliability standard is currently used by Energy Division in the RA LOLE modeling and we plan to continue to use that standard going forward.

Regarding AReM's proposal, we note that Energy Division conducted its LOLE study using Stress Test 3. For future RA LOLE studies, Energy Division should continue to perform similar stress tests to ensure monthly reliability levels. In D.24-06-005, the Commission "determined that a single PRM will apply to all hours of the year for initial implementation of the SOD framework."[46] However, following the initial implementation of the SOD framework, we recognize that a single PRM may not be appropriate for all hours of the year. As Energy Division conducts its PRM calibration analyses, Energy Division is authorized to conduct an optional stress test analysis to set a single annual or multiple PRMs, as necessary.

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[45] Public Utilities Code Section 380(h)(4).

[46] D.24-06-005 at Finding of Fact 3.

4.3. Unforced Capacity (UCAP) Methodology

Vistra recommends the Commission direct a UCAP working group to provide CAISO, Energy Division, and stakeholders with a venue to develop a UCAP methodology and submit a proposal in early 2026 to be adopted for the 2028 compliance year.[47] Vistra proposes that between Q3 2026 – Q3 2027, implementation efforts would include suppliers reviewing RA contracts to confirm NQC reductions, LSEs reviewing portfolios and procuring additional RA capacity, and suppliers appealing initial UCAP value. Vistra recommends that in August 2027, CAISO publish the draft and final NQC, which will include NQC values based on UCAP for the 2028 NQC list.

CESA supports Vistra's proposal for resource-specific UCAP accreditation in 2028 and for storage UCAP values to be calculated only after sufficient, consistent historical outage data is available from CAISO.[48] SDG&E generally supports UCAP implementation and argues that adoption earlier than 2028 would be difficult in potentially forcing LSEs to make solicitation decisions without full information.[49]

CAISO states that it will begin a stakeholder process to consider a UCAP framework, which will provide a venue for stakeholders, Energy Division, and other local regulatory authorities in the CAISO balancing authority area.[50] CAISO states that if Vistra's proposal is adopted, the Commission should ensure close coordination with CAISO's stakeholder process and that CAISO will work with Energy Division to align a potential UCAP framework.

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[47] Vistra Track 2 Proposal at 7.

[48] CESA Comments on Track 2 Proposals at 5.

[49] SDG&E Comments on Track 2 Proposals at 6.

[50] CAISO Comments on Track 2 Proposals at 6.

PG&E states that it is premature to determine that 2028 is the appropriate implementation year and notes that because Energy Division has been working on UCAP for some time, earlier implementation is possible.[51] PG&E states that the timing of UCAP should be aligned with PRM changes, which does not have an established cadence. PG&E supports the principles it raised in Track 1 for a UCAP methodology but notes that it may not be feasible for a final methodology to be at the resource-specific level, which should be further explored.

4.3.1. Discussion

In D.24-06-004, the Commission stated that:

> The Commission observes that a broad range of parties agree that further discussion is needed to develop a UCAP methodology for thermal and storage resources. As such, we decline to adopt a UCAP methodology at this time. We note the UCAP framework is being further developed in Track 2, as a UCAP framework is intended to be used for 2026 RA LOLE modeling efforts and for developing forced and ambient outage derates for the 2026 compliance year at the earliest.[52]

The Commission agrees with PG&E that it is premature to determine that 2028 is the appropriate implementation year for a UCAP methodology. We note that Energy Division has been working on a UCAP methodology for over a year and CAISO will be initiating a stakeholder process on a UCAP methodology. As such, Energy Division should coordinate with CAISO to develop a UCAP accreditation methodology for thermal power plants and battery electric storage systems for consideration in advance of the 2028 RA compliance year and to submit a revised UCAP proposal in Track 3 of this proceeding.

[51] PG&E Comments on Track 2 Proposals at 6.

[52] D.24-06-004 at 63.

Due to the work already underway towards a proposed UCAP methodology, an additional working group process is unnecessary; rather, we encourage parties to participate in CAISO's stakeholder process and/or submit proposals or evaluate Energy Division's proposal in Track 3 of the proceeding. Energy Division should harmonize its UCAP proposal with CAISO, to the extent possible, and coordinate on critical issues, including: (1) identifying one source of data; (2) identifying the correct treatment of nature of work codes; (3) specifying how to determine UCAP for new resources; (4) determining the appropriate level of aggregation/disaggregation of similar resources; (5) determining how to accommodate for different outage types, such as maintenance and thermal ambient derates in addition to pure equipment failure curtailments; and (6) determining a protocol for outliers and missing data.

The Commission notes that only curtailments and outages will be assessed for the UCAP methodology. We agree with CalCCA that forced outage rates for storage resources should reflect plant failures but not state-of-charge, as the model used in SERVM already accounts for state-of-charge when dispatching storage.[53] A battery resource's state-of-charge is somewhat analogous to onsite fuel storage and somewhat analogous to resources with long start-up times, neither of which are incorporated into UCAP for conventional resources. While a grid resource's interactions with other resources (including a storage resource's ability to be charged and ready when needed) are important to overall reliability, these interactions are modeled separately from the forced outage events outside the control of resource operators, which UCAP is intended to address. The

[53] _CalCCA Reply Comments on Track 2 Proposals at 6

UCAP methodology for battery storage should therefore incorporate forced outages due to equipment failures, but not state-of-charge.

The Commission further notes that Energy Division's Track 1 UCAP proposal provided that Energy Division does not support resource-specific accreditation "in large part due to the confidential nature of the GADS data from which we source EFORd values, necessitating aggregation such that they cannot be attributed to individual resources."[54] Even if data is sourced from public sources, there is also the issue of data quality and completeness. The Commission notes that it may not be feasible for a final UCAP methodology to be at a resource-specific level unless a procedure is developed to correct anomalous or missing data from specific plants, and therefore, additional class groupings should be considered. We encourage Energy Division to coordinate with CAISO to develop data acquisition and analysis procedures using alternative public sources, to the extent possible, for a UCAP methodology and to develop a protocol with CAISO to account for missing or outlier data.

4.4. Major Reforms to the CPE Framework

AReM, CESA, and MRP put forth proposals to eliminate the CPE framework and/or eliminate the local RA requirements, as summarized below.

AReM states that the current CPE framework has resulted in inefficiencies in the RA market and has been unsuccessful in procuring the required local RA capacity. AReM thus proposes to eliminate the CPE framework and the local RA requirements, and instead allow LSEs to procure system RA obligations with the expectation that resources needed for local reliability will be procured and

54 Energy Division's Track 1 Proposal, January 19, 2024, at 17.

shown to meet system RA requirements.[55] AReM states that if specific resources needed for local reliability are not procured, they can be procured through CAISO's Capacity Procurement Mechanism (CPM) authority or using the Cost Allocation Mechanism (CAM). AReM argues that this proposal would reduce the complexities of procurement with little or no detriment to local reliability because local resources are expected to be procured with system resources. AReM adds that this proposal allows the impacts of IRP procurement to be considered alongside the impacts of SOD procurement.

CESA recommends reverting to the former local RA program if the CPE framework is dismantled.[56] CESA contends that eliminating the local RA program entirely is shortsighted and that the local RA requirements are valuable in resolving defined local reliability issues. CESA posits that in future years, it may not be the case that LSEs will procure local resources to meet overall system requirements.

MRP recommends eliminating the CPE framework because more mature procurement by LSEs has reduced the need for CPEs to procure on LSEs' behalf and the CPE framework rules impede longer-term cost-effective contracts needed to retain existing resources and to develop new resources.[57] MRP proposes a new track in 2025 to discuss dismantling the CPE framework for 2026.

4.4.1. Comments on Proposals

Calpine supports dismantling the CPE structure and reverting back to the former local RA rules.[58]

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55 AReM Track 2 Proposal at 7.

56 CESA Track 2 Proposal at 3.

57 MRP Track 2 Proposal at 4.

58 Calpine Comments on Track 2 Proposals at 5.

Cal Advocates, CalCCA, and PG&E oppose eliminating the CPE framework.[59] CalCCA argues that significant changes to the RA program should not be considered until after the SOD program has been implemented and tested. CalCCA states that constant shifting of the compliance framework and rules of the RA program makes it challenging for the market to adjust and could be harmful to the market. PG&E likewise objects to a major overhaul of the CPE framework and notes that while in a tight system RA market, resources needed for local reliability will be contracted to provide system and flexible RA, this may not be the case with excess RA resources. PG&E states that eliminating the CPE framework would be disruptive and likely result in a less reliable grid and potentially higher prices.[60]

Cal Advocates asserts that the CPE's targeted procurement of local resources is important to provide reliability benefits, and a deficient sub-area may lead to immediate load shed after a single contingency. Cal Advocates states that the CPEs' market power mitigation tools, including deferring procurement for high priced offers, are critical during periods of elevated RA prices.

CAISO, MRP, and SCE oppose eliminating the local RA requirements.[61] CAISO argues that system RA requirements do not have enough geographic granularity to ensure sufficient resources are available in local capacity areas. CAISO states that local requirements are needed to ensure adequate capacity to

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[59] CalCCA Comments on Track 2 Proposals at 9, Cal Advocates Comments on Track 2 Proposals at 11, PG&E Comments on Track 2 Proposals at 5.

[60] PG&E Reply Comments on Track 2 Proposals at 2.

[61] CAISO Comments on Track 2 Proposals at 6, MRP Comments on Track 2 Proposals at 10, SCE Comments on Track 2 Proposals at 8.

meet reliability needs in local areas and encourage new development in local areas. MRP states that the local requirements represent requirements that must be satisfied by CAISO to comply with adopted reliability criteria. SCE does not support removing local requirements if the CPE framework is dismantled and states that LSEs can use local load shares to inform their system RA procurements on a yearly basis.

4.4.2. Discussion

The Commission declines to dismantle the CPE framework or eliminate the local RA requirements. Energy Division's May 2024 Report on the 2021-2023 CPE Framework (CPE Report) was the Commission's first comprehensive review of the CPE framework and we find it premature and unnecessary to dismantle the CPE framework at this time without further discussion and a more developed record. The Commission agrees with parties that such a drastic change would be greatly disruptive to the RA program, particularly as the program is transitioning to full implementation of the SOD program in 2025.

Further, we agree that system RA requirements alone cannot target local reliability areas with the same granularity as local RA requirements, and thus cannot ensure that sufficient resources are procured in local areas. While parties' proposals focus on the current tight RA market conditions in which local RA resources are being contracted for system RA needs, we caution that these market conditions could evolve as newer resources are built, potentially resulting in system RA requirements being inadequate to meet local RA needs. In addition, one of the CPEs' key tools is to defer to backstop procurement (i.e., decline to procure) to mitigate market power when prices are too high. A CPE's decision to decline to procure is analogous to the local RA waiver process that allows for an LSE to receive a waiver if local RA prices were above a certain threshold, among other requirements. For these reasons, we decline to dismantle the CPE framework or eliminate the local RA requirements. We next consider parties' proposals to refine the existing CPE framework.

4.5. Refinements to the CPE Framework

4.5.1. Soft-Offer Price Cap Proposal

CESA and WPTF propose a soft-offer price cap for CPE procurement that would approximate the opportunity cost to LSEs of not procuring sufficient resources to meet RA requirements.[62] The proposed price cap would be based on the sum of CAISO's CPM soft-offer cap and the higher of the system or local RA penalty price.

CESA recommends that if an offer exceeds the price cap, the CPE is not obligated to accept the offer but has discretion to procure above the price cap if it determines the offer is in the best interest of ratepayers, subject to Commission approval. CESA states that this formalizes a process so that the CPE has clarity from regulators on whether an offer that exceeds the price cap is in the best interest of ratepayers before deferring to CAISO's backstop mechanism.

WPTF recommends that the CPE have discretion to accept bids above the price cap if it is in the best interest of ratepayers, but the CPE would not have discretion to reject bids below the price cap if the resources are needed to meet the CPE's procurement requirements in that local area. Both parties note that the Commission has previously stated that the CPE has discretion to defer procurement of local resources to CAISO's backstop mechanism "if bid costs are deemed unreasonably high" but has not provided guidance on what constitutes unreasonably high prices.

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62 CESA Track 2 Proposal at 10, WPTF Track 2 Proposal at 6.

4.5.1.1. Comments on Proposal

Several parties oppose the proposal, including AReM, Cal Advocates, DMM, PG&E, and SCE.[63] These parties generally state that a public soft-offer price cap is harmful to competition as capacity owners will bid up to the price cap, rather than bid competitively, and potentially raise costs for customers.

Cal Advocates argues that CPEs' discretion to defer procurement based on price is an important market power mitigation tool, especially when local capacity requirements are near or at the level of available capacity in a local area and there is a greater potential for market power. SCE notes that the Commission gave the CPE discretion to determine what "unreasonably high" bid costs are because the CPE's assessment is informed by several qualitative and quantitative factors that are not compatible with one definition. PG&E opposes the proposal because the CPEs already have authority to determine whether competitive offers are priced too high using public RA pricing information, competitive offers are evaluated against several criteria that influence whether or not to accept an offer, and the CAM procurement review group (PRG) and independent evaluator (IE) provide oversight of the process. DMM states that the price cap would far exceed the going-forward fixed costs and allow for local RA sellers to exert market power within that price range.

AReM contends that the proposal appears to be more about circumventing CAISO's soft-offer cap in the backstop procurement process than protecting reliability.[64] If the proposal was adopted for the 2023 and 2024 RA years, AReM

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[63] Cal Advocates Comments on Track 2 Proposals at 18, DMM Comments on Track 2 Proposals at 3, PG&E Comments on Track 2 Proposals at 3, SCE Comments on Track 2 Proposals at 9.

[64] AReM Comments on Track 2 Proposals at 4.

notes that the CPE may have procured more local resources at higher prices but that would not have impacted reliability, as CAISO did not need to perform backstop procurement despite PG&E's CPE being deficient. AReM posits that the proposal would raise costs for customers with no clear benefit for reliability when a lower cost backstop mechanism is available.

4.5.1.2. Discussion

The Commission finds that a soft-offer price cap has the potential to reduce competition and increase market power in exactly those locations where generation is controlled by few suppliers. We concur with parties that state that a public soft-offer price cap will quickly become a price floor as bidders are not incentivized to submit competitive bids below the price cap. This will drive up market prices and costs for all ratepayers, including unbundled customers that absorb prices through the CAM.

We also find that obligating CPEs to execute any contracts below the price cap will negate the CPEs' ability to procure local resources using least cost, best fit and other qualitative metrics, as the CPEs have been directed to do by the Commission in D.20-06-002. CPE procurements are subject to the oversight and review by the IE and CAM PRG, which ensures that solicitations and transactions are consistent with the Commission's directives and selection criteria. For these reasons, we decline to adopt a soft-offer price cap as part of the CPE framework.

4.5.2. Contract Transfer Proposal

MRP states that in its experience, once a CPE has procured capacity, the CPE is reluctant to change the transaction to allow LSEs to procure that capacity from the resource owner due to uncertainty about the CPE's ability to allow it, even if doing so would facilitate LSEs self-procuring their own local resource and reducing CPE procurement costs. MRP asserts that some LSEs seek longer-term system RA contracts, but those resources may be in local areas and have already been contracted by the CPE.

MRP proposes that the CPEs be authorized to allow capacity that was procured by the CPE to be later transferred to another LSE when the LSE elects to procure directly with the resource owner for a long-term contract (of 5 years or more) and the contract has an overlapping delivery period with the existing CPE contract.[65] The new LSE must self-show that capacity to the CPE for the initial delivery term with the CPE. MRP recognizes that this would impact other LSEs due to affected CAM credits but notes that there are multiple factors (*e.g.*, load forecast, NQC methodology) that also affect CAM credits.

Microsoft, Calpine, and WPTF support the proposal.[66] Microsoft states that LSEs should be encouraged to sign long-term contracts for local RA, at least until a comprehensive solution is developed between the IRP and RA proceedings. WPTF states that the proposal would result in LSEs receiving fewer system RA credits from the CPEs but would reduce overall CPE procurement costs allocated to LSEs.

CalCCA opposes the proposal and argues that it would exacerbate existing challenges LSEs face with predicting CPE RA allocations, as LSE allocations after CPE procurement could decrease or be eliminated entirely.[67] CalCCA notes that transferring CPE procurement does not increase the amount of capacity under contract but transfers the costs and benefits LSEs would already collectively pay

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[65] MRP Track 2 Proposal at 16.

[66] Microsoft Comments on Track 2 Proposals at 15, Calpine Comments on Track 2 Proposals at 7, WPTF Comments on Track 2 Proposals at 12.

[67] CalCCA Comments on Track 2 Proposals at 11.

to an individual LSE. CalCCA states that the proposal allows lower-priced contracts with the CPE to be abandoned for higher-priced ones with LSEs, and LSEs cannot defer to backstop procurement if prices are too high. PG&E opposes the proposal and agrees with CalCCA that the proposal would result in significant contracting uncertainty.[68]

The Commission declines to allow the transfer of CPE procurement contracts to individual LSEs. While the proposal may help one or more LSEs to secure a longer-term contract than the CPE may be willing to secure, we note that LSEs are currently able to engage in longer-term contract negotiations, regardless of the CPEs' positions or available solicitations. We agree with CalCCA that the proposal allows generators to abandon existing lower-price contracts with the CPEs, while the costs of that transfer are borne on deficient LSEs that cannot defer to backstop procurement if prices are too high. We also agree that this proposal will lead to greater uncertainty for LSEs in accounting for CPE allocations, and the proposal does not increase the amount of available RA capacity to contract. For these reasons, we decline to adopt MRP's proposal.

4.5.3. Proposals to Eliminate the Self-Showing Option

PG&E asserts that the PG&E CPE continues to face challenges procuring local RA capacity due primarily to an overall lack of participation, as a significant amount of local capacity is held by LSEs for system RA requirements and is not shown to the CPE.[69] PG&E states that this is further demonstrated by the fact that despite the CPE's deficiencies, CAISO has not undertaken backstop procurement designations after the CPE's annual local RA showing. PG&E

[68] PG&E Reply Comments on Track 2 Proposals at 8.

[69] PG&E Track 2 Proposal at 2.

states that due to this lack of participation, the CPE has incomplete information before the annual solicitation as to what local RA capacity is under contract by LSEs. Therefore, the CPE cannot make the best procurement decisions on behalf of customers, cannot secure the most effective local resources needed, and cannot mitigate backstop procurement.

PG&E states that the non-compensated self-showing process does not incentivize LSEs to self-show local resources for the three-year compliance period. PG&E proposes to eliminate the non-compensated self-showing process and instead have Energy Division collect local RA contracting information from LSEs to then distribute to the CPEs. PG&E states that removing the self-show process will eliminate the administrative work associated with self-showing and close the information gap CPEs need to inform procurement decisions.

PG&E recommends Energy Division include a modified template in the annual RA compliance process that requests information, including: Resource ID, local area, contract start/end date, technology type, and contracted monthly MW capacity for the three-year forward period. PG&E states that the information would not include LSE-identifying information and proposes a reporting deadline of January 31, 2025, as the information would not be used until after the annual RA compliance process. PG&E recommends that the CPEs send a letter to all LSEs with an existing and/or active attestation within 30 days of this decision to nullify remaining self-show commitments.

SCE recommends counting all shown system resources in local areas towards the CPEs' local RA obligation.[70] Because CPEs must file Annual Compliance Reports in September, LSEs that plan to include system RA in local

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70 SCE Track 2 Proposal at 3.

areas towards their system requirements would have to self-show the resource earlier than the October year-ahead filing deadline. This would force LSEs to self-show all resources in a local area and if the resource is shown on the supply plan as a system resource, it would equally count as a system and local resource and reduce the amount of local RA the CPE must procure.

WPTF proposes to refocus the CPEs' role on procuring resources to meet local requirements that have not been contracted by LSEs to meet system requirements.[71] WTPF recommends the CPE's role be limited to a backstop procurement with the self-showing option terminated and the Local Capacity Requirement Reduction Compensation Mechanism (LCR-RCM) discontinued. The CPEs would consult with the Commission and CAISO to determine whether there is a need to procure local RA based on the year-ahead RA compliance showing and RA plans. WPTF notes that the effectiveness of this proposal would depend in part on the adoption of multi-year forward system requirements and should be considered in alignment with the RCPPP.

4.5.3.1. Comments on Proposals

Calpine supports removing the uncompensated showing option, as it does not seem to be serving its function, and seeking information through Commission reporting will be more reliable and less cumbersome.[72] CEJA/Sierra Club support PG&E's proposal with the modification that the information reported to Energy Division should be aggregated by type of resource and be made public, as this would be important for determining what procurement gaps exist for phasing out reliance on gas plants.[73] CEJA/Sierra

71 WPTF Track 2 Proposal at 10.

72 Calpine Comments on Track 2 Proposals at 7.

73 CEJA/Sierra Club Comments on Track 2 Proposals at 18.

Club support SCE's proposal as important to ensuring all local resources are counted towards phasing out reliance on gas plants.

SCE generally supports PG&E's proposal but states that the information for year-ahead requests for offers (RFO) could be outdated because the CPE will receive the current year's local capacity information in January and the proposal assumes local capacity data from the Commission will remain the same for two years.[74]

CalCCA opposes PG&E's proposal, arguing that it is unclear why CPEs need the proposed information and that the information cannot be used to understand what may be bid or shown, as resources that are not contracted with an LSE may be contracted by a non-jurisdictional LSE or out-of-state entity.[75] If the purpose is to determine which resources are unavailable for CPE procurement, CalCCA states that the CPE would know this after those resources are not offered into the solicitation. CalCCA claims that existing firewalls to separate an investor-owned utility's (IOU) CPE functions and its LSE functions may not be sufficient to ensure IOUs do not have a competitive advantage over other LSEs. PG&E responds that it is not proposing changes to the solicitation process that would allow the CPE to eliminate a resource from consideration simply because it is under contract to an LSE.[76] PG&E asserts that CalCCA provides no basis to question whether the CPEs' existing firewalls are sufficient.

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74 SCE Comments on Track 2 Proposals at 11.

75 CalCCA Comments on Track 2 Proposals at 13.

76 PG&E Reply Comments on Track 2 Proposals at 5.

CalCCA and AReM oppose SCE's proposal.[77] CalCCA states that the proposal turns the CPE into a backstop entity, ignores the risks of self-showing by forcing LSEs to self-show (such as reducing flexibility to sell parts of a portfolio), and requires procurement decisions before the current deadlines. AReM agrees with CalCCA that it is unclear how much capacity is under contract and not self-shown by the year-ahead deadline and forcing self-showing will not result in a substantial benefit. AReM states that the market would be better served by Energy Division Staff contacting LSEs to encourage them to self-show and provide assistance with the self-showing process.

PG&E asserts that WPTF's proposal assumes resources needed for local reliability will be contracted to provide system and flexible RA.[78] PG&E states that substantial local reliability risks may result in a system RA market with excess resources, as the Commission and CAISO would need to ensure local resources are contracted through other means like the CPM. CalCCA agrees that WTPF's proposal should be considered in parallel with the RCPPP to ensure a coordinated approach to ensuring retention of existing resources needed for reliability.[79]

4.5.3.2. Discussion

In D.20-06-002, the Commission adopted a "hybrid" CPE framework, which allowed LSEs to procure local resources to meet their system and flexible RA requirements and voluntarily "show" their procured local capacity to the

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[77] CalCCA Comments on Track 2 Proposals at 13, AReM Reply Comments on Track 2 Proposals at 5.

[78] PG&E Comments on Track 2 Proposals at 5.

[79] CalCCA Comments on Track 2 Proposals at 10.

CPE to count the capacity towards the CPE's collective RA requirements.[80] The Commission determined that the hybrid framework, as opposed to a full or residual procurement model, "allows a CPE to secure a portfolio of the most effective local resources, use its purchasing power in constrained local areas, mitigate the need for costly backstop procurement in certain local areas, and ensure a least cost solution for customers and equitable cost allocation."[81] LSEs' option to voluntarily show their procured local capacity to the CPE has since been referred to as the non-compensated self-showing option (as compared to self-showing for compensation via the LCR-RCM).

Since the implementation of the CPE framework, however, the lack of participation in the non-compensated self-showing option by LSEs has been well-documented, particularly in the PG&E CPE's service territory. In D.22-03-034, the Commission stated that "a limited amount of local resources were self-shown to the PG&E CPE for no compensation" in the 2021 RFO solicitation.[82] The Commission noted that "[b]y self-showing local resources, LSEs can lower the overall amount of the CPE's local RA obligation, which reduces the amount of local resources the CPE must procure and thus lowers procurement costs for ratepayers in the CPE's service area."[83]

To encourage greater self-showing by LSEs, several modifications were adopted in D.22-03-034, including (1) requiring an attestation for self-showing rather than a binding contractual agreement;
(2) revising the CPE procurement timeline to give LSEs and CPEs a similar

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80 D.20-06-002 at 24.

81 *Id*.

82 D.22-03-034 at 13.

83 *Id*.

amount of time for procurement; and (3) requiring an LSE that declined to self-show or bid into the CPE solicitation to explain why it declined to self-show or bid.[84] In D.23-06-029, the Commission further modified the self-showing process to allow an LSE that self-shows to the CPE to sell the self-shown capacity to other LSEs, which we stated "may increase the amount of self-shown resources by removing a potential disincentive for self-showing and provide additional opportunities for LSEs to procure system and/or flexible RA."[85] The Commission also ordered the CPEs to report on resources that were not offered to the CPE in deficient areas and resources where an agreement could not be reached, to help LSEs manage upfront system RA procurement and understand the inventory of available resources. [86]

Despite multiple efforts over the last few years to increase LSEs' participation in the non-compensated self-showing option, there was continued lack of - and even decreasing – participation in self-showing in the PG&E CPE's 2021, 2022, and 2023 RFO solicitations.[87] Because of this, the Commission is concerned that the CPEs do not have access to critical information before initiating the CPE solicitation as to what local resources are under contract by LSEs, what the most effective local resources are to secure, and what the true needs are in designated local areas. Without this information, the CPEs cannot make effective procurement decisions and may under- or over-procure in local capacity areas, which increases costs to ratepayers and in the case of under-procurement, may result in backstop procurement.

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84 *Id*. at Ordering Paragraph (OP) 1, OP 2, OP 3, 14.

85 D.23-06-029 at OP 14, 49.

86 *Id*. at 46.

87 Energy Division's CPE Report at 47, PG&E Track 2 Proposal at 2.