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

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

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

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Table of Contents

Table of Contents continued

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Pursuant to the *Assigned Commissioner's Amended Scoping Memo and Ruling* filed December 16, 2020 (Amended Scoping Memo), the California Community Choice Association (CalCCA)[1] submits the following comments and answers to questions. The Amended Scoping Memo directed parties "to file responses to the questions listed in Attachment A. Comments and responses to the questions may be filed and served no later than January 22, 2021."

I. SUMMARY OF COMMENTS ON PROPOSED CHANGES TO PROCEEDING SCOPE

CalCCA supports the Amended Scoping Memo's addition of the following issues to the scope of Phase 2 of this Proceeding:

1) Should the Commission remove or modify the Power Charge Indifference Adjustment (PCIA) cap?

[1] California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Silicon Valley Clean Energy, Solana Energy Alliance, Sonoma Clean Power, Valley Clean Energy, and Western Community Energy.

2) Should the Commission modify deadlines or requirements of Energy Resource Recovery Account (ERRA) and PCIA related submittals and reports in order to increase time for parties to review PCIA data and to facilitate timely implementation of decisions in the ERRA proceedings?

3) Should the Commission adopt a methodology for crediting or charging customers who depart from the utility service during an amortization period and who are responsible for a balance in the PCIA Undercollection Balancing Account, the Energy Resource Recovery Account, or any other bundled generation account?

4) Should the Commission consider any other changes necessary to ensure efficient implementation of PCIA issues within ERRA proceedings?[2]

Each of these issues will play an important role in ensuring the stability of the PCIA charge and fostering the ability of Community Choice Aggregators (CCAs) to have equal, transparent and timely access to the data underlying PCIA changes.

Issue 1. CalCCA supports the elimination of the PCIA cap and trigger mechanism to reduce volatility and bring greater stability in the PCIA rate. As a part of agreements with the investor-owned utilities (IOUs) in the most recent Energy Resource Recovery Account (ERRA) forecast proceedings, CalCCA anticipated supporting a petition for modification that the IOUs intended to submit to eliminate the cap and trigger mechanism. [3] The Amended Scoping Memo eliminates the need for this petition. CalCCA discusses its support for cap and trigger elimination in section II of these comments.

Issues 2 and 4: CalCCA members have previously raised concerns regarding the IOU annual ERRA submittals and process. The Scoping Ruling's addition of ERRA process and schedule issues will build on the changes the Commission adopted in recent ERRA forecast

[2] Amended Scoping Memo, at 1.
[3] *See, e.g.*, D.20-12-038 at 12; D.20-12-035 at 52.

proceedings[4] and bring uniformity across the IOUs. In addition to these ERRA-specific rulings, the Commission should require the IOUs to:

- Make available to designated reviewing representatives the following:
    - Confidential versions of the monthly ERRA and Portfolio Allocation Balancing Account (PABA) reports (Monthly Reports) for each month of the year at the time such confidential versions are provided to the Commission; and
    - The same data and workpapers underlying those reports, at the same level of granularity, that are now required to be provided as part of the future ERRA forecast proceedings in each IOU service territory;
- Work with parties to this proceeding to develop non-disclosure agreements (NDAs) that are non-docket specific and specifically allow for reviewing representatives to use the data in the Monthly Reports to create PCIA rate forecasts that do not disclose confidential data and can be shared with market participants; and
- Make consistent their designation of data sets (*e.g.*, total portfolio costs) as either confidential or public across all three IOUs.

Issue 3. CalCCA agrees that crediting or charging customers who depart during an ERRA under- or overcollection amortization period must be addressed. While a common methodology has emerged over the past few years – applying charges or credits to the most recent PABA vintage, which includes both bundled and recently departed customers – the methodology has been applied inconsistently across (and even within) proceedings. Moreover, a timing problem risks misalignment of ERRA costs and cost causation: ERRA proceedings cover calendar years, while customer vintages span calendar years. Consequently, applying charges or credits accrued during a calendar year to a vintage that mixes customers who were bundled customers when the under- or over-collection accrued and departing load customers who were not risks inequitable treatment of one customer category or the other.

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[4] D.20-12-035, at Ordering Paragraph (OP) 8; D.20-12-038, at OP 4; D.21-01-017, at OP 6.

II. ANSWERS TO QUESTIONS POSED IN APPENDIX A OF THE AMENDED SCOPING MEMO

A. The Power Charge Indifference Adjustment (PCIA) Cap

1. Should the Commission remove or raise the PCIA cap? Please provide rationale for your answer.

The Commission should remove the PCIA cap. The current iteration of the PCIA cap stemmed from concerns the CCAs had about a lack of transparency underlying, and the resulting inability to plan for, the large swings in the PCIA that can occur both within one year and from one year to the next. CalCCA proposed a collar on the PCIA to promote rate stability,[5] with the understanding that, if the Commission adopted certain of CalCCA's other recommendations (which were rejected), the PCIA would eventually decrease, or increase at a more sustainable rate, allowing for any revenue owed to bundled customers to be paid back in subsequent, low-PCIA years. Instead, the Commission adopted a $0.005/kWh cap proposed by direct access providers and a PCIA trigger proposal from The Utility Reform Network that was based on the existing ERRA trigger mechanism.[6]

The Commission's stated rationale for adopting a cap was to avoid PCIA volatility: "We find that the potential for volatility supports adoption of a PCIA cap in this decision. Such a cap should reduce extreme PCIA price spikes, and bill impacts, but not enable a continual state of significant undercollection.[7] Similarly, "[w]e affirm that a cap protects against volatility in the PCIA."[8] As formally set forth in Finding of Fact 18: "A PCIA cap will limit the change of the

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5 D.18-10-019, at 132.
6 D.18-10-019, at 134, Finding of Fact (FOF) 19.
7 D.18-10-019, at 85.
8 D.18-10-019, at 86.

PCIA from one year to the next. A cap that limits the change of the PCIA from one year to the next promotes certainty and stability for all customers within a reasonable planning horizon."[9]

Unfortunately, the cap has failed to achieve its purpose. Rather than reducing volatility, it has increased volatility and uncertainty. To understand why volatility has increased requires delving into the details of the cap, the associated trigger, and how they have played out in practice.

Soon after adopting a cap, the Commission established balancing accounts – the PCIA Undercollection Balancing Accounts (PUBA) and Cap Balancing Account (CAPBA) -- to "track any obligation that accrues for departing load customers. . . .any balances in the account will be repaid to bundled customers with interest."[10] The cap deferred, not avoided, cost responsibility. In practical terms, unbundled customers borrow from bundled customers to finance the revenue shortfall the utility would otherwise see from application of the cap. The difference between what PCIA customers pay with a capped rate versus what they would have paid with an uncapped rate accrues in a balancing account, for unbundled customers to repay down the road.

When does repayment come due? That depends on how quickly balances build up. In the normal course, "[t]he year-end balances in the balancing accounts established pursuant to sub-paragraph (d)[sic.] above shall be incorporated into the PCIA calculation for the following year."[11] That is, if balances stay below a threshold level, and (by implication) the following year's rate is below a capped level, the prior year's balance will be recouped there. If the next year's rates are also capped, the balancing account will continue to grow. However, if the

[9] D.18-10-019, at FOF 18.
[10] D.18-10-019, at 86; *see also* D.18-10-019, at OP 9(b).
[11] D.18-10-019, at OP 9(c).

balance builds up to a threshold amount within a given year, then a PCIA "trigger mechanism" kicks in, and repayment obligations can arise in the same year that the cap is in effect.

The Commission adapted the PCIA trigger mechanism, and the associated thresholds, from the ERRA trigger mechanism.[12] The PCIA trigger mechanism operates as follows:

a. he PCIA trigger threshold is 10% of the forecast PCIA revenues.

b. If PG&E, SDG&E, or SCE reach 7%, and forecast that the balance will reach 10%, they shall, within 60 days, file expedited applications for approval in 60 days from the filing date when the balance reaches 7%.

c. The application shall include a projected account balance as of 60 days or more from the date of filing depending on when the balance will reach the 10% threshold.

d. The application shall propose a revised PCIA rate that will bring the projected account balance below 7% and maintain the balance below that level until January 1 of the following year.

e. If PG&E, SDG&E or SCE reach 7%, and forecast that the balance will reach 10%, they shall, within 60 days, file expedited following year, when the PCIA rate adopted in that utility's ERRA forecast proceeding will take effect.[13]

Unfortunately, the combination of the cap and trigger has exacerbated, rather than reduced, PCIA rate volatility, due in part to the erroneous assumption seen in paragraph 2 above that a PUBA balance, like an ERRA balance, can somehow self-correct.[14]

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[12] D.18-10-019, at 86.

[13] D.18-10-019, at OP 10(a), (d).

[14] A PUBA balance cannot self-correct because the rate differential between capped and uncapped PCIA rates is fixed (whereas the ERRA rate can decrease if the wholesale cost of electricity decreases). Thus, the only variable that modifies the PUBA balance is the amount of departing customer load. Thus, a PUBA balance cannot decrease, and the rate of accumulation can only slow if departed customers use less load or stop using electricity altogether.

In 2020, PG&E,[15] SCE,[16] and SDG&E[17] all reached the trigger filing threshold of 7% within a few months of 2020 PCIA rates going into effect. Each utility proposed different approaches to drawing down their respective balancing account balances, but the uniform effect was to substantially raise PCIA rates not just to, but above, the capped level (or, in an alternative formulation, to impose an adder atop PCIA rates for unbundled customers, and a credit for bundled customers). In SDG&E's case, it proposed for unbundled customers an astounding 1,438% *month-over-month* increase under one method, or a 230% month-over-month increase under an alternative method.[18]

The Commission mitigated the impacts of these proposals for 2021 by amortizing the balances over three years (rather than three months, as SDG&E proposed,[19] or a single year, as PG&E proposed), and raising the combined PCIA rate and associated surcharge to a level that avoids further balance accruals while amortizing the existing balances. Even with the Commission-approved mitigation approach, unbundled customers are seeing a substantial increase in PCIA rates from 2020 to 2021. On a system average basis, PG&E customers will see PCIA increases up to 40% with SCE and SDG&E increasing up to 55% and 39%, respectively. Moreover, in addition to payback of balances leading to a large increase in unbundled customer PCIA rates, unbundled customers in vintages prior to 2020 are also paying a systemically higher

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15 A.20-09-014, *Expedited Application of Pacific Gas and Electric Company (U 39 E) Under the Power Charge Indifference Trigger*, at 2 (September 28, 2020).

16 A.20-10-007, *Expedited Application of Southern California Edison Company (U 338 E) Regarding the Power Charge Indifference Trigger*, at 1 (October 9, 2020).

17 A.20-07-009, *Expedited Application of San Diego Gas & Electric Company (U 902 E) Under the Power Charge Indifference Adjustment Account Trigger Mechanism*, at 1-2 (July 10, 2020) (SDG&E CAPBA Trigger Application).

18 SDG&E CAPBA Trigger Application, at 6-7 (For a 3-month period, a typical residential departing load customer in the 2015 PCIA vintage using 400 kWh would have seen a monthly increase of $187 (from $13 to $200) using generation revenue allocation factors and of $30 (from $13 to $43) using an equal cents per kWh vintage rate.).

19 SDG&E CAPBA Trigger Application, at 6-7.

PCIA rate than customers in later vintages, as unbundled customers repay the above-cap amounts from 2020.

The key to reducing volatility is to stop the growth of the balances that might cause another trigger in future years while simultaneously drawing down existing balances. And that means eliminating the cap. Unless the cap is eliminated, we may well see a replay of the 2020 scenario in future years, with the added complexity of overlapping multi-year amortizations and vintaged balancing accounts. We need to get off this merry-go-round.

Considering these dynamics, CalCCA members – whose customers are the cap's ostensible beneficiaries – see the cap and trigger mechanism as an added source of uncertainty and volatility. First, because even if capped rates apply in a given year, unbundled customers have to prepare to pay back the looming balancing account balances as those balances build up. Those balances can be substantial, as demonstrated in just the few months of 2020 that gave rise to the utilities' trigger filings.[20]

Second, the deferral is brief. It would only be a one-year deferral under the "normal course" scenario set out in Decision (D.) 18-10-019, before any trigger. With a trigger, the deferral is even shorter. Under SDG&E and PG&E's trigger proposals, the cap would only have been in effect for eight months.[21] After collaborating in the short time allowed within the trigger timelines, CalCCA, its members, and the IOUs joined together in recommending that the balances be amortized over three years rather than just one, but still beginning in January 2021.

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[20] *See* D.20-12-038, at 20 ("PG&E forecasts a year-end PABA under-collection balance of $462 million for 2020, based on recorded data through September 2020 plus a forecast of the remaining three months.").

[21] SDGE's 2020 PCIA rates were effective February 1, 2020 per Advice Letter (AL) 3500-E. The utility's CAPBA proposal would have increased rates beginning in October 2020. PG&E's rates were effective May 1, 2020, per AL 5781-E. PG&E's PUBA trigger proposal would have increased rates beginning January 1, 2021.

Third, drawing down the balances raises unbundled customer PCIA rates above those of bundled customers, all else equal. This creates a competitive imbalance between IOUs and unbundled service providers.

Fourth, uncertainty around whether/when a trigger filing will occur makes rate planning more difficult.

Fifth, and finally, there is significant administrative overhead and litigation expense associated with PUBA and CAPBA trigger filings.

In recognition of these effects, CalCCA agreed with the IOUs to support an end to the cap. We continue to support ending the cap and removing the trigger mechanism and urge the Commission to do so.

2. If you think the PCIA cap should be raised, explain by how much it should be raised and provide rationale for your answer.

CalCCA does not recommend raising the cap amount. Any level of cap will present some or all of the same issues that the current cap presents. True, a higher cap (all else equal) means balances would grow more slowly than they currently do since the difference between capped and uncapped rates is reduced. But the balances will still grow, there could still be trigger filings, and the balances will still have to be repaid leading to higher PCIA rates for unbundled than bundled customers as repayment comes due (see the third point above). The Commission should prevent these dynamics by removing the cap and trigger mechanism.

3. Would removal of the PCIA cap have an impact on Community Choice Aggregators' or Electric Service Providers' overall financial viability? Please provide a financial analysis to demonstrate the impact.

No, for all the reasons discussed in response to question 1. In addition, the cap, after the first year of implementation, does not operate as a cap. This occurs because the trigger amount is recovered as a rider to the capped PCIA rate.[22]

4. What principles or other factors should inform the Commission's consideration of any modifications to the cap and trigger process?

The key principle for any modification to the cap and trigger is whether the modified cap and trigger mitigates PCIA volatility while maintaining a level playing field between bundled and unbundled customers.

5. The investor-owned utilities must file expedited applications for approval in 60 days from the filing date when the trigger balance reaches 7% of forecast PCIA revenues.

a. Should the Commission revisit the 60-day timeframe?

CalCCA proposes to eliminate the cap and trigger mechanism and thus eliminating the need for these expedited applications. If the California Public Utility Commission (Commission) retains the mechanism, however, it should hold workshops describing how to modify the trigger application process. Most critically, any trigger mechanism should avoid same-year rate increases. As the trigger operates now, it can result in multiple PCIA increases in a year, increasing uncertainty and impairing CCA planning.

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[22] *See, e.g.,* D.20-12-035, at OP 1; D.20-12-038, at OP 6 (ordering SCE to apply a "PCIA Trigger Mechanism Surcharge" to departed load customers in addition to the capped PCIA rate).

b. Are there other modifications to the PCIA trigger mechanism that the Commission should consider, such as revisiting the PCIA trigger amount currently set to 10 percent of forecast PCIA revenues? If so, explain in detail the proposed modification and provide rationale for your answer.

CalCCA proposes to eliminate the cap and trigger mechanism, thus eliminating the need to consider trigger thresholds. If the Commission elects to retain the cap and trigger mechanism, CalCCA recommends workshops to consider this and other questions.

6. Should the PCIA cap be applied to the prior year's forecast PCIA rate, or each prior year's final PCIA rate that includes the true-up recorded actuals for energy and the Commission-issued final Resource Adequacy (RA) and Renewables Portfolio Standard (RPS) adders? Provide rationale for your answer.

CalCCA proposes to eliminate the cap and trigger mechanism and thus eliminating the need for to consider the mechanics of cap application. If the Commission elects to retain the cap and trigger mechanism, CalCCA recommends workshops to consider this and other questions.

7. Should the Commission adopt a methodology for crediting or charging customers who depart from the utility service during an amortization period and who are responsible for a balance in the PCIA Undercollection Balancing Accounts, the Energy Resource Recovery Account (ERRA), or any other bundled generation account? Explain in detail what methodology you recommend and provide rationale for your answer.

Yes, the Commission should develop and adopt a uniform methodology for addressing the application of ERRA charges or credit to bundled and departing load. To some degree, a common methodology has emerged via recent ERRA and PUBA/CAPBA trigger proceedings, but the methodology has been applied inconsistently across (and even within) proceedings and suffers from a significant short-coming resulting from a timing mismatch between ERRA forecast periods and customer vintage periods. Thus, in establishing this methodology, the Commission should consider the distortions and equities that could result from such a mismatch.

The methodology also should make certain that cost recovery or credit aligns squarely with cost causation. Lastly, the methodology should be applied uniformly across utilities and proceedings.

Before the details of this question can be considered, however, the question itself requires some clarification. It suggests that a customer departing utility service might be "responsible for a balance in the PCIA Undercollection Balancing Accounts." However, customers departing utility service can only be *owed* a PUBA balance from when they were bundled customers (*i.e.*, the customers overpaid their obligations on account of the PCIA rate cap when they were bundled customers and then departed). Departing customers would only be "responsible" for a PUBA balance if they were departed customers when a PUBA balanced accrued and then opted out to *return* to bundled service (*i.e.*, the customers underpaid their obligations on account of the PCIA rate cap when they were unbundled customers and then returned to bundled service).

With that clarification in mind, yes, the Commission should adopt a common methodology for all utilities for crediting or charging customers who depart from utility <u>or CCA</u> service during an amortization period and who are responsible for, <u>or owed</u>, a balance in the PUBA/CAPBA, the Energy Resource Recovery Account, or any other bundled generation account.

a. A Uniform Application of Methodologies to Credit or Charge Bundled and Recently Departed Customers Is Needed

Generation balancing accounts such as those for bundled ERRA rates accrue overcollections when rates are either set too high, or demand exceeds forecasted loads, over the course of a year. These overcollections represent a refund owed to customers that should be paid back to those customers. The inverse problem arises for charges to recover undercollected balances. In recent ERRA forecast and trigger proceedings, stakeholders and the Commission have coalesced around a methodology that credits (or charges) the most recent vintage in the

PABA to effectuate the refund by reducing the future generation rates customers will pay (rates would increase in the event of an undercollection). Since both bundled and unbundled customers pay the PCIA, the reduction in the PABA effectively refunds most customers that are owed a credit (and charges most customers that have underpaid).

PG&E's 2020 ERRA forecast case demonstrates this approach. In D.20-02-047, the Commission agreed with the Joint CCAs that a net ERRA overcollection must be reflected in the PCIA rate, and that the "overcollection credit should benefit all customers who paid into the overcollection."[23] The Commission ordered PG&E to "include in its Energy Resource Recovery Account Forecast application for 2021 a method to properly credit vintage 2019 and 2020 departed load customers that does not have adverse effects on PCIA vintage subaccounts."[24]

PG&E proposed returning the end-of-year ERRA balance going forward, "less the deferred revenue financed by bundled customers due to capped PCIA rate," to the 2020 vintage and that this approach be standardized for future years.[25] PG&E explained the purpose of the transfer is to "ensure that the 2020 overcollected ERRA is returned to the Vintage 2020 non-exempt departing load customer and remaining bundled customers."[26] Because customer vintages are determined on a July to June schedule, PG&E's proposal to transfer year-end ERRA balances to the most recent vintage on a going-forward basis would ensure customers departing

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[23] D.20-02-047 at 11.

[24] D.20-02-047 at OP 4.

[25] A.20-07-002, Exh. PG&E-1 at 19-7:6-15 and 19-4:22-25. PG&E also proposed to credit a proportional share of the 2019 ERRA end-of-year balance to 2019 vintage departing load customers through a one-time PCIA rate adjustment for that vintage. A.20-07-002, *Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2021 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and* Reconciliation, at 5, 12-13, 18, 21 (July 1, 2020).

[26] *Id*. at 14-14:2-4.

"on or after July 1" are credited (or charged) for the ERRA balance accruing during the year of their departure.[27]

The Commission adopted PG&E's approach in D.20-12-038 but, as discussed in more detail below, did not determine it should be applied in all future years because it did not address all customers that were owed a refund.[28] Nonetheless, similar approaches have also been adopted with regard to ERRA trigger undercollections in SCE's service territory (A.18-11-009),[29] and with regard to CAPBA financing in SDG&E's service territory (A.20-07-009).[30] SDG&E's ERRA Trigger Application, A.20-12-007, also proposes a one-time transfer to PABA to address an ERRA undercollection that accrued during 2020.[31]

There are two shortcomings with this approach. First, it has been inconsistently applied to recently departed customers who, like bundled customers, financed a PUBA balance. For example, over the Joint CCAs' objections, D.20-12-038 returned PG&E's PCIA Financing Subaccount (PFS) to bundled customers via the ERRA rather than the PABA.[32] As a result, some of the funds owed to currently bundled customers who depart PG&E service during the amortization period will never receive them. Because returning an ERRA overcollection to bundled customers has the same effect as reimbursing bundled customers for having financed the

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27 A.20-07-002, Exh. JCCAs-1 at 37:20 to 38:3.

28 D.20-12-038, at 22.

29 *See* D.19-01-045, at OP 2 (stating "Southern California Edison Company shall collect the Energy Resource Recovery Account undercollection through a pro-rata apportionment of the costs to 2018 SCE bundled service customers, including 2018 and 2019 vintage departing load customers, utilizing bundled service allocation factors established in D.18-11-027, and using the Power Charge Indifference Adjustment as the rate recovery vehicle for the undercollection amount.").

30 D.20-12-028, at OP 4 (ordering "a one-time transfer of the CAPBA overcollection due to bundled customers into the 2020 vintage of its Portfolio Allocation Balancing Account").

31 A.20-09-014, *Expedited Application of San Diego Gas & Electric Company (U 902 E) Under the Energy Resource Recovery Account Trigger Mechanism*, at 2 (December 11, 2020); A.20-09-014, *Prepared Direct Testimony of Stacy Fuhrer on behalf of SDG&E*, SF-8 (December 11, 2020).

32 D.20-12-038 at 21-22.

PUBA,[33] the Joint CCAs argued it should have been paid back in the same manner prescribed by D.20-02-047 for an ERRA overcollection, *i.e.*, "reflected in the PCIA rate" to ensure any overcollection credit benefits "all customers who paid into the overcollection."[34] This approach would have comported with an approach already codified in SCE's PABA implementing advice letter, which returns the PUBA balance via the PABA, ensuring customers that are owed a refund would receive one.[35]

The PG&E decision did not, and could not, explain why those purported differences warrant such an inequitable outcome. The decision states only that "Southern California Edison structured its financing subaccount differently than PG&E, and therefore it is reasonable for PG&E to have a different approach to returning balances to bundled customers."[36] That is, the decision promoted PG&E's preferred accounting treatment over providing full refunds to ratepayers that paid into a balance they were owed. However, the Commission did state it "may consider structural changes to the [PFS] when we address PCIA framework issues in the appropriate proceeding."[37] The Commission should address such revisions as part of this proceeding.

More broadly, recent decisions establishing three-year amortization periods for the PUBA balances for PG&E and SCE and the CAPBA for SDG&E did not address customer

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33 A.20-07-002, Exh. JCCAs-1 at 41:11-13.

34 D.20-02-047, at 11.

35 SCE AL 4084-E and SCE Preliminary Statement Section Q.3.b (stating "The year-end balance in this subaccount is returned, in its entirety with interest, through a transfer to the applicable vintage subaccount of the PABA.").

36 D.20-12-038 at 21-22.

37 D.20-12-038 at 21-22.

crediting for years other than 2021.[38] Thus, a crediting methodology must still be developed (and uniformly implemented) for 2022 and 2023.

CalCCA supports the approach that has emerged over recent years, which most closely aligns cost responsibility with cost causation, but it must be applied uniformly. Transferring the amount due customers who were bundled customers at the time the cost was incurred to the recent PABA vintage(s) ensures that all customers – bundled or recently departed – receive credit for their share of an ERRA overcollection or PUBA/CAPBA balance they helped finance. This approach aligns with long-standing ratemaking principles, is simple to implement, and will produce a uniform approach for balancing account under collections across all utilities.

b. The Problem Is Complicated by the Mismatch Between the Vintaging Methodology and Ratemaking Calendar

The second shortcoming with the current approach is that customers that depart in the first half of a year in which an overcollection accrues are unlikely to receive any credit for refunds they are owed (with the inverse being true in the case of an undercollection). This issue stems from the fact that vintages are set with a mid-year cutoff, while PCIA and ERRA rates are (generally) set on a calendar year basis. A hypothetical overpayment through, say calendar year 2019, if refunded to *vintage* 2019 will be underinclusive. Why? Because the vintaging rules' June cut-off means *vintage* 2019 does *not* include customers who departed January through June 2019. Those customers are vintage 2018. So even though they left IOU service in 2019 and

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[38] D.20-12-028, at OP 4, at 22 (SDG&E) ("We recognize the importance of approving a consistent method for returning balances to customers but will not adopt PG&E's going-forward proposal at this time. We will consider a long-term solution when we address PCIA framework issues in the appropriate proceeding."); *id.* at 9 ("In this decision we do not rule on SDG&E's argument, made in its reply briefs, that the Commission should require departing customers leaving SDG&E in the middle of 2021 to forgo a refund, though we do approve a one-time transfer of the CAPBA overcollection due to bundled customers into the 2020 vintage of PABA."); *see* D.20-12-035, at OP 6 (SCE); *see also* D.20-12-038, at 18, OP 1 (PG&E).

would have contributed to the amount being refunded, they would not see a refund. While you could pick those customers up by refunding to the 2018 vintage, now you would be overinclusive, since some of the 2018 vintage customers would in fact have left in calendar 2018, and not contributed to the amount being refunded.

This quandary was considered in the PG&E 2021 ERRA forecast case above, where customers receiving a credit were those who departed on or after July 1, 2020 (or remained bundled PG&E customers) and paid into ERRA for at least the first half of 2020.[39] However, customers that overpaid in 2020, but left during the first half of 2020, would not receive a refund to which they are entitled when the most recent vintage (in this case, 2020) is credited via PABA because those customers are 2019 vintage customers. Stated another way, the refund misses "half" the vintage.

It was for this reason the Commission did not formally adopt PG&E's approach of crediting the most-recent vintage on a going-forward basis.[40] As part of this expanded proceeding, the Commission should explore how to resolve this problem consistently and equitably, by revising the vintaging rules, modifying the ratemaking calendar, or another approach.

B. Improving PCIA and ERRA Alignment

1. How should the Commission modify the deadlines and requirements of ERRA and PCIA-related submittals and reports in order to increase time for parties to review PCIA data while facilitating an ERRA implementation on January 1 of each year? Explain in detail the proposed modification and provide rationale for your answer.

The CCAs have repeatedly requested opportunities to revise the annual ERRA process, and resulting Annual Electric True-Up (AET), to ensure both stakeholders and the Commission

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39 A.20-07-002, Exh. JCCAs-1, Attachment B, PG&E's response to Joint CCA DR 3.34.

40 D.20-12-038, at 22.

have sufficient time to adequately analyze the complex and high-stake issues in an ERRA proceeding, while also acknowledging the need to litigate the proceeding on an expedited timeline. In 2019, the CCA parties to PG&E's ERRA Forecast proceeding sought "Commission guidance for a forum in which more concrete procedural mechanisms might be adopted for all IOU ERRA processes."[41] CalCCA appreciates the Assigned Commissioner's response by amended the Scoping Ruling for this phase.

Thematically, the challenges parties (and, by extension, the Commission, where it relies on parties for record development) face break down into two categories:

(1) Challenges accomplishing needed work given unusually short deadlines, and

(2) Challenges obtaining needed information from utilities (which then exacerbate problem (1)).

The Joint CCAs laid these challenges out graphically back in 2019. Harking back to the experience of 2018, Joint CCAs stated:

> Addressing the November Update was a difficult task—an exercise in legal triage that barely maintained due process thanks to an extraordinary ALJ ruling and the unusual but necessary step of requiring a Tier 2 Advice letter to implement an ERRA forecast decision. It required analyzing 80 pages of updated testimony, scrutinizing 13 sets of workpapers, participating in two informal workshops, submitting and reviewing responses from two sets of discovery totaling 29 data requests (excluding tens of additional sub-parts), drafting 35 pages of comments, and submitting a Motion to add 15 exhibits to the record. The parties had ***<u>10 days</u>*** to accomplish all of these tasks, which turned into 12 days given the timing of the update resulted in a Saturday deadline.[42]

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[41] A.19-06-001, *Protest of the Joint CCAs to the Application of Pacific Gas and Electric Company (U 39 E) for 2020 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast And Greenhouse Gas Forecast Revenue Return And Reconciliation*, at 28 (July 5, 2019) (referencing, A.18-06-001, *Assigned Commissioner's Scoping Memo And Ruling*, at 4 (Aug. 16, 2018)).

[42] *Id.* at 30.

It is incumbent upon CCAs to assist the millions of unbundled customers in California in planning for rate changes in the ERRA that, in the past, have led to significant, volatile and near-term changes in customers' monthly electricity bills. The opacity of IOU filings, and the Commission's ERRA framework in general, have repeatedly and consistently frustrated CCAs' efforts to advocate for their customers.

a. Master Data Requests and More Detailed and Timely Workpapers Are Necessary to Ensure Full and Fair Data Access by Customers Paying the PCIA

In each of its recent ERRA forecast decisions, the Commission took strides toward leveling the playing field within those proceedings and increasing LSEs' ability to predict and plan for PCIA rate changes that primarily rely on confidential, utility-specific cost and revenue data. For example, in D.20-12-035, the Commission found that "[c]ertain market participants, including CCAs, require timely access to SCE's ERRA/PABA/PUBA reporting as well as precise volume of RA, RPS and other metrics in order to meet their evidentiary burden in the ERRA forecast proceeding."[43] It further determined that delaying access to the "ERRA/PABA/PUBA and other reports concerning the validity of SCE's ERRA forecast application until the November Update, and requiring extensive discovery requests to obtain this information, creates additional administrative burdens for the parties to the proceeding as well as Commission staff."[44]

The Commission required SCE to "provide the following information in Energy Resource Recovery Account (ERRA) forecast proceeding workpapers and monthly ERRA compliance reports, starting January 2021:

(a) Confidential version of monthly ERRA/PABA/PUBA activity reports;

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[43] D.20-12-035, FOF 38.
[44] D.20-12-035 at 56.

(b) Additional detail supporting the monthly PABA reports, including subcategories for summarized line items such as utility-owed generation (UOG) costs and contracts (*e.g*., provide by resource type, and whether Renewables Portfolio Standard (RPS) or non-RPS eligible);

(c) Actual or accrued volumetric quantities underlying each relevant dollar figure; such categories include UOG generation, power purchases and sales, California Independent System Operator market sales, and retail customer sales;

(d) Monthly accrued volumes of Actual Sold, Retained, and Unsold Resource Adequacy capacity; and

(e) Monthly accrued volumes of Actual Sold, Retained, and Unsold RPS-eligible energy.[45]

The Commission made nearly identical findings and orders in both PG&E and SDG&E's ERRA Forecast decisions, requiring a Master Data Request in the PG&E case.[46] The Commission also specified in that case the following process: "After PG&E has filed an ERRA forecast application, and so long as such application is pending, PG&E will provide the specified information to reviewing representatives that have signed a nondisclosure agreement within 5 days after it submits each monthly ERRA/PABA/PUBA activity report to the Commission."[47] Requiring the data in the SCE case be provided, and this PG&E process to be followed, by all IOUs in their respective ERRA Filings will ensure uniformity in CCAs' access to data and significantly improve transparency in these expedited and opaque proceedings.

b. Equal, Transparent and Timely Access to Data are Necessary During all 12 Months of the Year.

The ability of CCAs to have equal, transparent and timely access to the data underlying changes to the PCIA has been a consistent point of contention for many years. Under the Commission's indifference framework, the PABA and the PCIA are inextricably linked to IOU

45 D.20-12-035 at OP 8.
46 D.20-12-038, 31-32 and OP 4; D.21-01-017 at OP 6.
47 D.20-12-038, 31-32, Conclusion of Law 11, and OP 4.

data the CCAs currently cannot access on a periodic basis outside of an active ERRA proceeding. This prohibition even applies to the CCAs' reviewing representatives under D.06-06-066 and the Commission's confidentiality framework. Those data include foundational data such as actual retail customer sales, which can significantly impact the PABA due to typical factors like weather and atypical factors like the COVID-19 pandemic and the IOUs' Public Safety Power Shut-off events.

As D.20-12-038 recognizes, each utility "already provides certain data regarding its ERRA/PABA/PUBA balances and other metrics associated with its ERRA forecast to the Commission on a monthly basis."[48] However, the monthly reports do not include volumetric data, which is necessary to understand why the PCIA is moving the way it is moving and to predict where the PCIA may head in the future based on different scenarios.

Thus, while the actions the Commission took to increase transparency in the ERRA Forecast proceedings will be helpful, year-round access to key cost and revenue data for the CCAs' designated reviewing representatives is the next critical step. Only year-round access to data achieves a level playing field in LSEs' ability to plan for PCIA rate changes and accurately forecast which direction those changes will go. As D.20-12-038 recognizes, "[g]ranting independent consultants access to confidential market sensitive information, under appropriate non-disclosure agreements, is a reasonable means of allowing market participants to review confidential versions of ERRA/PABA/PUBA reports."[49]

For this reason, the Commission should require the IOUs to make available to designated reviewing representatives the following:

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48 D.20-12-035, Conclusion of Law 39.

49 D.20-12-035, OP 5.

- Confidential versions of the Monthly Reports for each month of the year at the time such confidential versions are provided to the Commission; and
- The same data and workpapers underlying those reports, at the same level of granularity, and within the same schedule, that is now required to be provided as part of future ERRA forecast proceedings in each IOU service territory.

In light of the fact that much of the information contained in these reports is confidential, it would be appropriate for the Commission also require the IOUs work with parties to this proceeding to develop NDAs that are non-docket specific, *i.e.*, NDAs that would apply to year-round provision of confidential data. The NDAs should also specifically allow for reviewing representatives to use the data provided in the Monthly Reports outside the context ERRA Forecast proceedings for the limited purpose of creating PCIA rate forecasts that are based on, but do not disclose, confidential data, and can be shared with CCA decision-makers to allow them to plan for future rate changes.

c. Discovery Timelines Should Be Tightened

Subject to the caveat that parties reasonably limit the number of requests, CalCCA suggests the following discovery timelines:

- Between the Application Date and Rebuttal Testimony – 10 Business Days (BDs)
- Between Intervenor Testimony and IOU Rebuttal Testimony – 5 BDs
- Between IOU Rebuttal Testimony and Hearings – 3 BDs
- Between final Update and Comments to final Update (or Intervenor Updated Testimony) – 2 BDs

In addition, parties should be required to serve workpapers concurrently with testimony and any updated or supplemental testimony in each ERRA forecast proceeding, and all workpapers should have (a) formulas intact, (b) underlying data included, and (c) avoid the use of hard-coded data that have little value.

d. A Modified Schedule Is Required to Reduce the Year-End Chaos Arising from November Updates

The Scoping Ruling rightly identifies the need to consider modifications of the current ERRA forecast requirements and schedules to bring greater transparency and efficiency to the process. While CalCCA is still considering the details of a modified schedule, certain issues warrant initial consideration. Most critical to CalCCA is ensuring the use of most current possible pricing data for market price benchmarks in ERRA forecast proceedings. Depending upon the broader direction of any changes, schedule modifications could include the following:

- ✓ Advance the submittal date for the November Update by one week.
- ✓ Following the November Update, set the following intervals for submittals:
    - o Comments on the November Update would be due between 12 and 15 days after its submittal, depending on how calendar plays out;
    - o Parties would be required to use their best efforts to respond to data requests within 3 business days;
    - o Comments on a proposed decision (PD) would be due between 7 and 10 days before meeting date at which the decision will be adopted;
    - o Reply comments on the PD would be due three days before the adoption meeting.

Finally, the Commission should consider the timing of PG&E's Annual Electric True-Up advice letter to avoid year-end confusion.

Optimally, however, schedule issues should be explored collectively among stakeholders, Key questions to explore include the following:

- Whether/how to constrain the final update in ERRA forecast proceedings to "turn of the crank" type changes (e.g., MPB updates), and avoid the surprises and litigation seen in the past several ERRA forecast proceedings;
- How to stagger IOU filings to reduce overlapping deadlines for staff common to multiple IOU ERRA proceedings;

- Whether to push the implementation date for new rates from January 1, 2021 to a later date; and

- Whether to push back the annual electric true-up filing for PG&E.

CalCCA recommends a workshop to explore these and other issues.

2. Should Commission's Energy Division release the Market Price Benchmarks (MPBs) earlier than November 1 of each year? If yes, what is a reasonable date and why?

CalCCA supports retention of the November 1 date for MPBs – a structure that was long considered in Working Group 1. D.19-10-001 sets for the rationale for this deadline, and nothing material has changed since that decision issued.[50] In general, the problems with the November Update referenced above have not been a function of MPB timing.

3. Are there any other procedural or information sharing related modifications the Commission should consider to support more efficient implementation of PCIA issues within ERRA proceedings?

The increases in transparency discussed throughout these comments will support more efficient implementation of PCIA issues within ERRA proceedings. In addition, the Commission can ease parties' review of the proceedings, and reduce the need for discovery and other administrative burdens by requiring the utilities to make consistent their designation of data sets as either confidential or public.

A particularly egregious example of this inconsistency is that SDG&E considers its total portfolio costs to be confidential, whereas PG&E and SCE reasonably provide this data as public. Additional examples of inconsistent confidentiality designations include:

- PG&E and SCE make public vintaged UOG General Rate Case (GRC) costs, procurement costs, and total vintage costs (i.e. the sum of UOG GRC costs + procurement costs). SDG&E provides neither procurement costs nor total costs; they provide only UOG GRC costs.

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[50] D.19-10-001, at 11-27 and OP 1.

- PG&E and SCE make public the total system sales, and sales within each vintage, used to derive the PCIA rates, with sales volumes are shown as annual kWh by class; SDG&E does not.
- PG&E and SDG&E make the on-peak and off-peak energy prices in the MPB available publicly; SCE does not.
- PG&E and SDG&E make the list of PCIA-eligible generation resources by vintage available publicly; SCE does not.

CalCCA recommends that the Commission direct consistency among IOUs on these issues with a goal of maximizing the extent of publicly available information.

III. CONCLUSION

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

Respectfully submitted,

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