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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)

COMMENTS OF PACIFIC GAS AND ELECTRIC COMPANY (U 39-E), SAN DIEGO GAS & ELECTRIC COMPANY (U 902-E) AND SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) ON ALTERNATE PROPOSED DECISION MODIFYING THE POWER CHARGE INDIFFERENCE ADJUSTMENT METHODOLOGY

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SUBJECT INDEX OF RECOMMENDED CHANGES

Pursuant to Rule 14.3 of the Rules of Practice and Procedure, Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) (together, the Joint Utilities), provide the following Subject Index of Recommended Changes in support of their Comments on the Alternate Proposed Decision (APD). In the final decision, the Joint Utilities respectfully request that the Commission:

- Reject the August 1, 2018 Proposed Decision (PD) in its entirety.
- Adopt the APD's correct legal and policy determinations regarding appropriate departing load cost responsibility for Utility-Owned Generation (UOG) and Energy Storage (ES) resources.
- Remove the APD's "cost cap" and "collar" restrictions for the Power Charge Indifference Adjustment (PCIA).
- Provide further clarity regarding the PCIA benchmark "true-up" methodology and process.
- Revise the APD to address the Joint Utilities' non-vintaging proposal for mandated "carve-out" procurement that is unrelated to load needs.
- Make technical changes to the APD to address certain accounting treatment and ratemaking issues for the PCIA calculation.
- Clarify the intended PCIA potential "pre-payment" process.
- Provide further guidance regarding the scope of Phase II of this proceeding.
- Implement the proposed language changes to the Findings of Fact, Conclusions of Law, and Ordering Paragraphs, as well as the proposed revisions to Appendix 1 to the APD, set forth in Attachment A to these Comments

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I. INTRODUCTION

Pursuant to Rule 14.3(b) of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission), Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E) and Southern California Edison Company (SCE) (together, the Joint Utilities), respectfully submit these comments on the *Alternate Proposed Decision Modifying the Power Charge Indifference Adjustment Methodology* issued by Commissioner Peterman on August 14, 2018 (APD).[1] The Joint Utilities continue to urge the Commission to consider adoption of their Green Allocation Mechanism / Portfolio Monetization Mechanism (GAM/PMM) proposal as the most equitable, sustainable, complete, and simplest approach to implement, and importantly, the only proposal that ensures the value of existing customer commitments is fully preserved regardless of the level of customer migration. However, with the important proposed modifications and clarifications discussed in detail below, the Joint Utilities strongly prefer the APD over the Proposed Decision (PD).[2]

Crucially, the APD reverses two fundamental and fatal flaws in the PD: its exclusion of legacy utility-owned generation (UOG) costs from the Power Charge Indifference Adjustment

[1] Pursuant to Rule 1.8(d), counsel for SDG&E confirms that counsel for PG&E and SCE have authorized SDG&E to file these Comments on behalf of the Joint Utilities.

[2] On August 21, 2018, the Joint Utilities submitted separate comments on the PD discussing in detail why the Commission should not adopt it.

(PCIA) for Community Choice Aggregators (CCAs), and its limitation of the cost-recovery period for post-2002 UOG and certain energy storage costs in the PCIA. Both results would have violated the statutory indifference requirement established by Public Utilities Code Sections 365.2, 366.2 and 366.3.[3] To ensure full compliance with that requirement, however, the final Commission decision in this proceeding should also eliminate the APD's "cost cap" and "collar" restrictions on annual changes to the PCIA. In addition, further clarity and details are necessary regarding benchmark and "true-up" issues to ensure customer indifference and equity. Finally, the Joint Utilities also suggest modifications and enhancements to the APD regarding appropriate cost recovery for "carve out" mandated procurement, accounting and ratemaking issues, PCIA "prepayment" options, and setting an appropriate scope for Phase II of this proceeding.[4] In accordance with Rule 14.3(b), the Joint Utilities have included an attachment reflecting proposed wording changes to the Findings of Fact, Conclusions of Law, and Ordering Paragraphs of the APD, as well as proposed revisions to Appendix 1 of the APD.

II. THE APD CORRECTLY REVERSES THE PD'S UNLAWFUL RESTRICTIONS ON UOG COST RECOVERY FROM RESPONSIBLE CUSTOMERS

A. The APD Correctly Includes Legacy UOG in the PCIA

The APD correctly concludes as a matter of law that Legacy UOG must be included in the PCIA in order to uphold the statutory indifference requirement. The PD's removal and exclusion of these costs from the PCIA rates of CCA customers was manifestly unlawful, in addition to being inequitable and inconsistent with public policy. It is beyond reasonable dispute that these resources were built on behalf of all then-bundled service customers, that they are managed by the Joint Utilities on behalf of all customers subject to this Commission's oversight pursuant to Standard of Conduct 4, and that as a matter of public policy their net costs must be shared equitably and *pro rata* by all responsible customers.[5] Many of these resources have been

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[3] All statutory references herein are to the Public Utilities Code unless otherwise noted.

[4] In addition, pursuant to the stipulation between the Joint Utilities and CLECA, the Joint Utilities agree that "allocation factors (such as top 100 hours) to rate/customer classes" are "properly addressed in GRC Phase 2 cases." *See* Exhibit IOU-CLECA-1, p. 3.

[5] Pursuant to D.18-07-037 (approving the SONGS OII Settlement Agreement), and the pending February 1, 2018, Motion for Adoption of Settlement Agreement in the 2017 ERRA Forecast Phase 2 Consolidated Proceedings (A.16-04-018, *et. al.*), pre-2009 vintage departing load customers in SCE's

providing (and continue to provide) valuable local reliability and non-greenhouse gas (GHG)-emitting benefits for California customers for decades, and in some cases, more than a century. Exempting CCA customers – but only CCA customers – from cost recovery for these legacy resources is incompatible with fundamental tenets of basic fairness and customer equity.

Moreover, the PD incorrectly focuses on a singular statutory provision that enumerates certain costs – but not Legacy UOG – as eligible for PCIA cost recovery from CCA customers. Not only does that section *not exclude* Legacy UOG costs from such cost responsibility, but the PD's strained reading[6] of that narrow section cannot be squared with its complete disregard for the broad provisions – including in the same statute – that unambiguously and completely ban any cost-shifting.[7]

Statutes must be read in their totality to give meaning to their underlying intent. Here, the Legislature could not have been more clear: cost-shifting is strictly prohibited. The statutory cost-shift-prohibition is absolute, and not limited to specific resource categories. The lack of specific statutory enumeration of Legacy UOG in 2002 as a resource category for whose costs CCAs would be responsible cannot be read as the Legislature intending an "exemption" for CCA customers from responsibility for the above-market cost of these resources, when considered in the overall context of the statutory indifference requirement. Indeed, thirteen years later in 2015,

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service territory are to be exempt from PCIA charges retroactive to January 1, 2017. The Joint Utilities, California Large Energy Consumers Association (CLECA), and Alliance for Retail Energy Markets and Direct Access Customer Coalition (AReM/DACC) all agree that appropriate PCIA cost responsibility for pre-2009 vintage departing load customers should be determined in the 2017 ERRA docket and not in this proceeding. In the 2017 ERRA docket, the parties have developed a robust and complete record on that issue, and it is fully briefed and submitted to the Commission for final adjudication. Attachment A hereto proposes changes to the Findings of Fact and Conclusions of Law reflecting that broad consensus.

6 For one thing, the PD relies on the argument that the Commission will not engage in "guessing what the Legislature may have included on a list of costs for which departing load would not be responsible." PD, p. 56. No such guessing is necessary. Later in the same statutory subdivision the Legislature did provide such a list, exempting CCA customers from "charges for goods, services, or programs that do not benefit either, or where applicable, both, the customer and the community choice aggregator serving the customers." Section 366.2(k)(1). Legacy UOG, of course, benefits both.

7 *See also* D.18-07-046, p. 4 ("It is not necessary to determine or prove the actual magnitude of the cost shifting because the law precludes any cost shifting.") (citing Sections 366.2 and 380; denying application for rehearing of Resolution E-4907). For other reasons to reject the PD's exclusion of Legacy UOG costs from the PCIA applicable to CCA customers, see *Comments of [Joint Utilities] on Proposed Decision Modifying the Power Charge Indifference Adjustment Methodology*, pp. 7-10.

the Legislature re-affirmed the absolute prohibition of cost-shifting resulting from departing load, and did not repeat the enumeration of specific categories of "eligible" PCIA resources.

The APD, on the other hand, correctly recognizes that both Assembly Bill (AB) 117 and Senate Bill (SB) 350 make explicitly clear that cost-shifting between customers is prohibited:

- AB 117 (2002): "The implementation of a community choice aggregation program ***shall not*** result in a shifting of costs between the customers of the community choice aggregator and the bundled service customers of an electrical corporation." (Section 366.2(a)(4) (emphasis added)).

- SB 350 (2015): "Bundled retail customers of an electrical corporation shall not ***experience any cost increase*** as a result of the implementation of a community choice aggregator program." (Section 366.3 (emphasis added)).

Because Legacy UOG is currently above-market, excluding it from the PCIA – by definition – would mathematically shift costs to remaining bundled service customers. That result would plainly violate black-letter California law, and would leave a final Commission decision incorporating it "extremely vulnerable to successful judicial review."[8]

B. The APD Correctly Eliminates the Artificial Time Limit on Inclusion of Post-2002 UOG and Energy Storage Costs in the PCIA

The APD also correctly eliminates the existing 10-year limitation presumption for departing load customer cost responsibility for the above-market costs of post-2002 UOG and energy storage (ES) resources. For the same reasons that both CCA statutes mandate equitable cost recovery from all responsible customers for Legacy UOG to prevent cost-shifting, they require the same result for post-2002 UOG and ES resources. The APD correctly recognizes that artificially limiting that cost responsibility to 10 years would impermissibly shift costs to remaining bundled service customers after the cost recovery period ended.

The PD, on the other hand, would artificially and arbitrarily limit such cost recovery to a 10-year period to provide the Joint Utilities with an "incentive" to "aggressively" manage their portfolios.[9] The PD's position is not only impractical and shortsighted,[10] but it also fails to

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[8] *Opening Comments of [TURN] on the Proposed Decision of ALJ Roscow* (August 21, 2018) (TURN Opening Comments on PD), p. 3.

[9] PD, p. 59.

[10] From a practical perspective, the only way to "manage" a long UOG "portfolio" is to retire or sell the units to non-regulated market generators. The former is incompatible with system reliability needs in

recognize that the statutory indifference requirement is not limited in time, nor is it specific to any given resource type (*i.e.*, renewable, conventional, etc.) or ownership structure (*i.e.*, utility-owned or utility-contracted). The APD, on the other hand, correctly recognizes that the Commission's legal obligation to preserve customer indifference is absolute.

III. THE APD'S IMPOSITION OF A COST CAP IS ARBITRARY, LACKS EVIDENTIARY SUPPORT, AND WOULD SHIFT COSTS TO BUNDLED SERVICE CUSTOMERS

The APD would establish a rate collar of 25 percent in either direction from the previous year's PCIA starting in forecast year 2020.[11] Consistent with the PD, the APD finds that a PCIA collar does not violate the indifference principle because "any balances in the account will be repaid to bundled customers with interest."[12] While the APD's rate collar is a marked improvement from the PD's wholly unsupported 2.2 cent/kwh rate cap, there is similarly no evidentiary basis for establishing the proposed collar as a matter of policy, nor for the 25 percent range for the rate collar.

Section 1701.2(e) requires that a decision "shall be supported by findings of fact on all issues material to the decision, and the findings of fact shall be based on the record developed." If the Commission wishes to establish a cost cap for the PCIA, which it should not, it must declare in its findings of fact that: 1) a cap is necessary to further a clear policy objective; 2) the level of the cap is reasonable; and 3) the cap will not violate the statutory requirement for customer indifference. These findings of fact are critical because "[s]uch findings afford a rational basis for judicial review and assist the reviewing court to ascertain the principles relied upon by the [CPUC] and to determine whether it acted arbitrarily."[13] The APD, however, contains no findings of fact that would support a PCIA cost cap or collar because there is no

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many cases. The latter raises serious market-power concerns, as many of these resources are located in local transmission-constrained areas. The UOG resources at issue were identified as being either the lowest-cost, best-fit solution at the time they were built or were needed to carry out a specific Commission policy directive.

[11] APD, p. 70 and OP 6(b).

[12] *Id*, p. 70.

[13] *Clean Energy Fuels Corp. v. Pub. Utilities Com.*, 227 Cal. App. 4th 641, 648 (2014).

evidentiary record to support such findings; consequently, cost caps and collars should not be instituted.

A. The Record Lacks Any Policy Justification for the Imposition of a Rate Collar

The Commission has established that cost caps must be substantiated and justified, because "[a]s a general principle of regulation, it is desirable to charge customers based on the costs to serve them."[14] In establishing the cost cap for the Cost Responsibility Surcharge (CRS) for Direct Access (DA) customers, the Commission determined that a cost cap was justified because without one, "the economic viability of DA as a continuing option" would be "seriously threaten[ed]."[15] Similarly here, the Commission must first find that the viability of DA and CCA options would be jeopardized without a cap; otherwise there is no possible justification for having bundled service customers finance the deferral of costs attributable to departing load customers.

The APD, like the PD, makes no such finding regarding the economic viability of CCAs and DA in the absence of a PCIA cap. Nor could it. There is no record evidence to support such a finding. In fact, the record evidence supports a contrary finding. As the Joint Utilities noted in their Opening Brief, California Community Choice Association (CalCCA) has represented to the Commission that "[m]any CCAs have rate stabilization funds that can be used to buffer rates in the event of a sudden spike in wholesale energy markets."[16] CalCCA has further represented that these rate stabilization funds allow CCAs to remain competitive in the event of "increases to non-bypassable charges, including the PCIA in particular" and that "it would likely take several years of upward market conditions to exhaust any such reserve or rate stabilization fund."[17] These representations are borne out by record evidence that Sonoma Clean Power expected to have over $40 million in its reserve accounts in 2017; Marin Clean Energy reported reserves of $50 million.[18]

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[14] D.03-07-030, p. 26.

[15] *Id.*, p. 8.

[16] *CalCCA Comments on the California Consumer Choice Project Workshop*, p. 5, *available at* http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/CA%20Community%20Choice%20Aggregators.pdf.

[17] Exhibit IOU-100, pp. 26:19 - 27:5.

[18] Exhibit IOU-120, PDF pp. 6, 11.

In addition to the complete absence of any record evidence demonstrating the need for a PCIA cost cap to preserve the economic viability of CCAs, the Joint Utilities have demonstrated that the PCIA and market prices are inversely correlated.[19] In other words, the PCIA increases when overall market costs are low, thus providing for a potential offset of costs.

There is no reasonable policy justification for capping the PCIA. The law does not contemplate a cost cap to promote further adoption of CCAs, or to protect the CCA business model at the expense of bundled service customers. The Joint Utilities respectfully submit that neither should this be the Commission's primary concern in this proceeding. It is incongruent with tenets of equity that an ever-shrinking (and soon to be minority) population of bundled service customers finance and subsidize an ever-growing (and soon to be majority) population of departing load customers. The primary rationale offered for a cap on the departing load charge appears to be the concern that market volatility will negatively affect CCA/DA providers, but the Commission must give careful thought to whether it is reasonable for CCA/DA providers, who may soon serve the majority of load in California, to continue to seek protection from volatility – an inherent aspect of the energy markets – by shifting risk to remaining bundled service customers. The Commission should consider the answer to the rhetorical question posed during the evidentiary hearing regarding adoption of a cap, "[i]f we're doing that here again . . . are we really creating a market situation where [CCAs/ESPs] will be sustainable if their only sustainability is with the cap in place[?]"[20]

As SCE's Mr. Cushnie testified, "[n]obody has certainty in energy markets. The prices change all the time. There's volatility. There's market disruptions."[21] Indeed, this reality is highlighted by the Commission's recent affirmation of the viability of the statutory Energy Resource Recovery Account (ERRA) "trigger" mechanism, which allows the Joint Utilities to pass through unforeseen generation cost increases from market disruptions and volatility to

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[19] *See* Exhibit IOU-1, p. 4-35; *see also* Exhibit IOU-100, p. 28 and Evid. Hr. Tr., Vol. 3, pp. 610:13-611:16 (Fulmer conceding both PCIA and GAM/PMM rates are inversely correlated to market prices).

[20] Evid. Hr. Tr., Vol. 2, pp. 399:28 – 400:4 (Joint Utilities, Fang).

[21] *Id*., p. 260:16-19 (Joint Utilities, Cushnie).

bundled service customers in near real-time.[22] At some point – fast approaching, given current predictions of load departure – it will be incumbent upon CCA/DA providers to play by the same rules and to manage this inherent volatility on their own, without seeking to shift risk and cost away from their customers to remaining bundled service customers.

Finally, in considering whether it is necessary and in the public interest to impose a cap designed to protect CCA/DA providers from the realities of market volatility, the Commission should consider the implications of artificially depressing CCA/DA rates and imposing a corresponding increase in bundled service rates (caused by the temporary allocation of the under-collection from departing load customers to bundled service customers).[23] This would make the CCA/DA service offering appear (artificially) more attractive, but would ultimately harm customers and potential customers, who would have no visibility into the true cost of CCA/DA service. A capped departing load rate would give the false appearance of a low rate for CCA/DA service, without revealing to CCA/DA customers that the actual cost of service (which includes departing load charges) is higher than the rate charged by their provider or, more to the point, that they are actually obligated to pay the deferred under-collection.

The financial obligation incurred by CCA/DA customers due to the deferred under-collection would most likely be unanticipated and could lead to customer complaints, as well as confusion if departing load customers return to bundled service, but continue to see charges related to the CCA/DA service (*i.e.*, the deferred under-collection) on their bill.[24] In effect, a capped, artificially-depressed rate would operate as a "teaser" rate analogous to the low, introductory home mortgage rates leading up to the 2008 financial crisis. As SDG&E's Ms. Fang observed during the evidentiary hearing, a cap on the departing load charge would create "long run potential market instability because those customers are not seeing the true prices that are occurring in the marketplace."[25] The distorted price signals resulting from a cap on departing

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[22] *See* Section 454.5(d)(3) and D.15-05-008 at Conclusion of Law 1 ("duration of the ERRA trigger mechanism is the duration of the electric utilities' electricity procurement pursuant to Section 454.5.").

[23] Exhibit IOU-3, pp. 5-10:24 – 5-11:15.

[24] *See, e.g.*, Exhibit AD-1, p. 31 ("any obligations [for deferred under-collection] remain with the DA customer if it individually returns to bundled service.")

[25] Evid. Hr. Tr., Vol. 3, p. 425:19-22 (Fang).

load charges would hinder access to reliable information regarding pricing of service options – including by customers and potential customers of existing CCA/DA providers and, indeed, by cities or other communities determining whether to form a CCA.

B. The APD's Analysis of the Rate Collar is Legally Insufficient

Similar to its deviation from sound Commission policy in establishing a rate collar, the APD's setting of the rate collar at 25 percent does not comport with Section 1701.2(e). There is absolutely no record on a 25 percent rate collar: no parties proposed this amount, and as a result, there was no opportunity for parties to respond to its reasonableness. Furthermore, there was no analysis quantifying its impacts.

This failure to quantify the appropriate level for a PCIA rate collar stands in stark contrast to the Commission's painstaking efforts in setting the DA CRS cap. The Joint Utilities contrasted in detail the Commission's efforts in the CRS proceeding (nearly 100 pages of analysis in D.03-07-060) with the cursory discussion in this proceeding (three sentences) in their Comments on the PD, and do not repeat those arguments here. The APD's rationale for its creation of the 25 percent rate collar is wholly absent, which is understandable because there exists no record to support it. No proposal, discussion, or analysis was performed to assess the 25 percent rate collar. As such, it should be rejected by the Commission in the final decision adopted here.

C. The Rate Collar Results in Illegal Cost Shifts

Lastly, the APD's conclusion that no cost shift occurs with a cost cap "[b]ecause any balances in the account will be repaid to bundled customers with interest,"[26] is erroneous and counter to Commission precedent. The Commission decided in setting the CRS that to avoid running afoul of the statutory requirement of bundled customer indifference, ***"the period of deferral should be no longer than is absolutely necessary.***"[27] Yet the APD fails to establish any timeframe for the deferral, thereby making impossible a finding that bundled service customers will not be harmed by subsidizing the financing for a growing majority of departed customers. Furthermore, there is no record showing that a 25 percent rate collar with an "interest" backstop will ensure bundled service customer indifference, when it could lead to material cumulative

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[26] APD, p. 70.

[27] D.03-07-030, p. 26 (emphasis added).

undercollections, which could then potentially be avoided by departing load customers leaving the service territory or otherwise avoiding the deferred obligation (*i.e.*, not "repaying the loan"). An "interest" provision for a loan that may never be repaid is a legal fiction, and would not prevent a statutorily-prohibited, cost-shifting result. Moreover, the DA CRS cap only applied to a limited amount of load, whereas the APD's rate collar could quickly apply to the majority of the load.

For all these reasons, the Joint Utilities urge the Commission to remove the PCIA cost cap and collar construct from the final decision because it is unjustified and risks harming bundled service customers.

IV. THE APD CORRECTLY ADOPTS BENCHMARK TRUE-UPS BUT ADDITIONAL CLARITY AND DETAILS ARE NECESSARY

A. The RA Valuation Initial Benchmark and True-Up Mechanism is Generally Acceptable

The Joint Utilities appreciate the APD's acknowledgement that Resource Adequacy (RA) ratemaking forecast values in the PCIA should be based on more realistic current market prices (*i.e.*, those reflected in the CPUC's most-recent annual RA Report); differentiated between system-, local-, and flex-eligible resources (when such information is available); and discounted for historical levels of unsold quantities. The APD also correctly determines that the after-the-fact true-up must include actual market values and results, including a zero-dollar valuation for excess investor-owned utility (IOU) RA that is not used for bundled load compliance purposes and is unable to be sold. However, the APD's unexplained references to assigning a "de minimis" value to anticipated unsold excess IOU RA attributes in setting the benchmark should be removed in the final decision. To minimize volatility between the forecast and the true-up and to eliminate ambiguity over undefined "de minimis" values, the RA benchmark should be set in a manner that more closely reflects the true-up calculation. Specifically, any forecasted quantity of unsold RA should be assigned a value of zero in the benchmark setting process. Overall, using the "market results" structure for the benchmark – but even more critically for the true-up – is necessary to maintain statutory indifference and should be carried through symmetrically for all PCIA benchmarks, as discussed in detail below.

B. The REC/Green Adder Initial Ratesetting Benchmark and True-Up Mechanism Should Be Clarified

The APD also correctly acknowledges that the Renewable Energy Credit (REC), or "green adder" benchmark, should be based on more realistic current market prices (*i.e.*, newly-contracted Renewables Portfolio Standard (RPS)-eligible contracts from all load-serving entities (LSEs) or based on the Platt's index for Year 1). As set forth in extensive evidentiary detail throughout this proceeding, the current PCIA green adder vastly overstates the market value of the Joint Utilities' portfolios, causing massive cost shifts to bundled service customers. Indeed, the currently-inflated green adder is the single largest driver of the cost shifts occurring pursuant to the current methodology, and the APD's remedy of that inequity is imperative.

For purposes of the initial ratesetting exercise, it is important that the REC benchmark exclude contracts that are not reflective of broad, competitive markets for green energy; specifically "specialty carve-out" mandated IOU procurement and statutory "feed-in tariffs" should be excluded. Because the Joint Utilities are substantially long on RPS (and will be for the foreseeable future given current forecasts of departing load), their recent RPS-eligible procurement has been exclusively done to comply with Legislative or Commission requirements, not based on load need to meet general RPS requirements. Indeed, PG&E has not engaged in non-mandated, non-carve-out RPS procurement since 2013, and SCE has not done so since 2015. In contrast, the Joint Utilities' recently-contracted resources under these mandates are much more expensive than actual market prices for "generic" RPS products (which form the vast majority of the Joint Utilities' portfolios that the benchmark is intended to "value").[28] Including such carve-out resources in the initial ratesetting green benchmark will inevitably lead to an artificial overstatement of that benchmark and artificially-low initial PCIA rates. But, when the PCIA is trued-up to actual market results that are lower-priced than mandated procurement programs, it will result in PCIA rate increases. It is more appropriate and conducive to customer rate certainty to simply exclude these premium-priced, mandated resources from the benchmark calculation in the first place.

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[28] *See* Exhibit IOU-1, p. 7-6, n. 2 (noting differences between contract prices executed by PG&E in 2017 for BioMAT resources ($197/MWh) and ReMAT resources ($80/MWh) versus the cost of solar resources in 2016 (generally at or below $50/MWh with a few resources priced at approximately $30/MWh).

Even more importantly, however, the after-the-fact PCIA true-up for green energy must include actual market values and results, including a zero dollar valuation for IOU RECs offered for sale (*i.e.*, those beyond the bundled load compliance need) that are unable to be sold in that year. The Joint Utilities will make extensive (and repeated) efforts, consistent with applicable RPS Plans and/or AB 57 Bundled Procurement Plans (BPPs), to market and sell their unsold, unneeded long RPS positions, but there is no guarantee those efforts will ultimately be completely successful. If unneeded generated RECs are approaching the mandatory compliance retirement window (*i.e.*, 36 months) and they still have not been sold, they will need to be placed in the Joint Utilities' respective Western Renewable Energy Generation Information System (WREGIS) accounts and valued at zero in the event they were previously valued at a non-zero amount. Had the Commission adopted the Joint Utilities' GAM/PMM proposal, these long positions would not need to be liquidated, because the Joint Utilities' excess, unneeded RECs would have been simply and equitably allocated to all LSEs and retained their full market value, instead of included in the PCIA. But given the APD has instead chosen to continue with a benchmark structure, this true-up-to-actual-market-value methodology for RECs is absolutely mandatory to maintain statutory customer indifference.

To effectuate the true-up, the Joint Utilities propose that 1) RECs generated and used for compliance by the IOUs in the same year be valued at the adopted benchmark price (*e.g.*, Platts Portfolio Content Category (PCC) 1 Price for 2019); 2) excess RECs be marketed prospectively as PCC1 and retrospectively as PCC3 (for up to approximately 36 months following generation of the underlying resource); 3) any revenues from the sales of RECs be credited to the earliest vintage portfolio with REC products;[29] 4) any RECs offered for sale and not sold as a PCC 1 product or transferred to the IOU WREGIS account be valued and credited at zero;[30] and finally 5) all transactions be reported to the Commission for inclusion in the subsequent year's REC benchmark calculation. Attachment A sets forth in detail the structure for this necessary REC "true-up."

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[29] Crediting revenues to the earliest vintage portfolio with REC products ensures that the broadest set of responsible customers get a proportionate share of REC sales revenues as all customers in later vintages are also in every earlier vintage.

[30] The Joint Utilities are amenable to discussing potential RPS "bank" value optimization revisions in Phase II of this proceeding.

C. *The Brown Energy Benchmark and True-Up Provisions Are Generally Acceptable But Details Require Clarification*

The Joint Utilities generally agree with the APD's conclusion that the "brown energy" benchmark is not controversial and should be retained for the time being (with the APD's correct recognition that forecast costs must be trued-up to actual net market results realized by the Joint Utilities' portfolios). That being said, it is important to note the following:

- The "brown energy" benchmark is currently based on a forward-strip of on- and off-peak energy prices weighted by the load (*i.e.*, demand) profile of bundled service customers of each IOU. It is not reflective of the delivery profile of the individual Joint Utilities' vintaged generation (*i.e.*, supply) portfolios. After the true-up for actual market revenues and results, those two values could turn out to be very different,[31] and the Commission should carefully consider the rate-volatility implications of setting the PCIA forecast based on the former, while the true-up necessarily incorporates the latter.
- The potential disparity between forecast brown energy values and actual market results may also be exacerbated by the APD's continued use of "line-losses" to determine the market value of the brown benchmark. Continuing to incorporate line-losses in the benchmark results in double-counting, which will then have to be reversed in the true-up.[32]
- The after-the-fact true-up must also account for actual customer retail sales/usage, in addition to realized market revenues (*i.e.*, both the numerator and denominator in the PCIA equation need to be trued-up). Additionally, under the current PCIA methodology, the Competition Transition Charge (CTC) and PCIA revenue requirements allocated to each rate group are divided by the rate group-level sales of all system customers. Continuing to use forecast system level kWh sales in the denominator used to set the rates, as opposed to forecast kWh sales of those responsible for each vintaged portfolio, will result in lower rates than are

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[31] For example, while "average" market prices for energy for the year may be $35/MW-hr for demand (*i.e.*, load), the average MW-hr generated by the supply resources in the Joint Utilities' RPS-dominated portfolios may not capture nearly that much market revenue.

[32] *See, e.g.,* Exhibit IOU-3, p. 2-28.

necessary to collect the revenue requirement allocated to each rate group and a systematic understatement of customers' PCIA responsibility, which will then have to be reversed in the true-up process.

In the end, the true-up would correct for these "mismatches," but in order to provide greater customer certainty and PCIA rate stability it is more appropriate to avoid them in the first place. Attachment A proposes technical changes that would do so.

V. THE PORTFOLIO ALLOCATION BALANCING ACCOUNT SHOULD MAINTAIN THE VINTAGED SUBACCOUNT STRUCTURE

To implement the annual true-up, the APD requires the three IOUs each to "establish a Portfolio Allocation Balancing Account (PABA) with three subaccounts to account for the costs and revenues associated with the brown power index, the RPS Adder and the RA Adder."[33] Although the Joint Utilities support the concept of tracking costs, it should be noted that few contracts, and no UOG generation assets, distinguish costs by specific attributes (*i.e.*, energy, renewable or RA). That is, many contracts have a single per unit price and generation resource costs are cumulative. Only a predetermined allocation method for the costs could lead to such tracking, and no such allocation methodology has been proposed in the proceeding. Therefore, the Joint Utilities recommend eliminating the tracking of costs by the three components as directed by the APD. Market revenues, on the other hand, are more easily tracked based on the segmentation of brown power index, RPS Adder and RA Adder, given the structure of the market price benchmark and the proposed true-up to actual market values for these components.

Further, the Joint Utilities recommend the PABA include subaccounts by vintage with cost and revenue tracking as outlined in the Joint IOUs' testimony,[34] but modified to include recording of REC sales revenues, monthly REC value at the adopted market price benchmark (MPB), and an annual true-up entry for RECs to align with actual sales-weighted values compiled for the year. The original PMM structure already included the concept of recording the

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[33] APD, p. 97. Although the APD makes a passing reference to the ratemaking proposal made in Exhibit IOU-1, the APD does not appear to leverage any aspect of the Joint Utilities' PABA proposal which has a foundational structure rooted in the establishment of subaccounts. The Joint Utilities' original proposal had both vintaged GAM subaccounts and vintaged PMM subaccounts, but the PMM subaccounts, by vintage, would be the appropriate template to consider in the context of the APD's adoption of updated market price benchmarks, with true-up.

[34] Exhibit IOU-1, pp. 4-48 and 4-49 (Section D.1.b, and Figure 4-4, PABA – PMM subaccounts).

RA value at the adopted MPB with an annual true-up entry for RA to align with actual sales-weighted values compiled at the end of the year, and the APD should retain that aspect of the vintaged subaccount proposal for all values.

A vintaged subaccount approach is necessary to maintain indifference between different vintages of departing load customers, to differentiate the treatment of REC market value in the cost recovery mechanism, and to ensure the proper allocation and tracking of billed revenues, as well as generation resource revenues and costs for the true-up mechanism.

The Joint Utilities also propose to file a Tier 2 implementation advice letter 60-days after the issuance of a final decision. The PCIA implementation advice letter would include each utility's proposed PABA preliminary statement and modifications to the ERRA and other generation-related balancing accounts needed to implement the final decision's directives. The implementation advice letter would also include (1) a proposal regarding the timing and regulatory proceeding where the annual true-up entries would be presented for review, (2) details regarding how the true-up formula would capture the REC and RA attributes used for bundled service customer compliance, and (3) sales-weighted REC and RA true-up for attributes in the Joint Utilities' respective portfolios that are in excess of those needed for bundled service customer compliance.

VI. COSTS OF MANDATED PROCUREMENT SHOULD NOT BE VINTAGED

The primary purpose of this proceeding is to eliminate the cost shifts between bundled service customers and departing load customers, as required by statute. However, the APD fails to consider the Joint Utilities' proposal to maintain customer indifference by eliminating the "vintaging" of resources for which the Commission has mandated procurement irrespective of whether the IOU needs the resources to serve its load.[35] Such mandated procurement programs include the Renewable Market Adjusting Tariff (ReMAT), the Bioenergy Market Adjusting Tariff (BioMAT) and Renewable Auction Mechanism (RAM), and the Commission's Public Utility Regulatory Policies Act (PURPA) program.[36]

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[35] *See generally*, Exhibit IOU-1, pp. 7-3:27 – 7-6:23. As noted in footnote 4 above, the Joint Utilities, CLECA, and AReM/DACC all agree that appropriate PCIA cost responsibility for pre-2009 vintage departing load customers should be determined in the 2017 ERRA docket and not in this proceeding.

[36] Exhibit IOU-1, Table 7-1.

These IOU-only mandated procurement programs were developed to support specific State policy objectives, such as reducing GHG emissions. All customers benefit equally from these policy-directed programs, and all customers should contribute *pro rata* to their costs. It is inequitable and illogical for an ever-dwindling pool of bundled service customers to pay 100 percent of the costs for resources that are not needed to meet bundled service customer load, but instead were developed to support various State or federal policy objectives that benefit *all* customers.

To ensure bundled service customer indifference, as well as indifference between vintaged portfolios, the Joint Utilities respectfully request the Commission determine that the costs of these programs must be recovered from all benefitting customers through the removal of the vintaging construct for those select resources.[37]

VII. PREPAYMENT GUIDELINES IN THE APD MUST BE CLARIFIED AND ADDITIONAL ISSUES RELATED TO PREPAYMENT MUST BE CONSIDERED IN PHASE II

The Scoping Memo asked whether the Commission should adopt an option for departing load customers to prepay the PCIA on a one-time basis in order to be relieved of the PCIA burden going forward.[38] The APD concludes that DA customers and CCAs, on behalf of their customers, should be permitted to prepay their PCIA obligations, subject to Commission approval on a case-by-case basis.[39] The APD makes clear that proposed prepayment arrangements that do not adequately balance risk to bundled service customers against benefits to departing load customers will be rejected.[40] The APD further emphasizes the voluntary and conditional nature of such arrangements, making clear that the Commission will not require the Joint Utilities (on behalf of their bundled service customers) to accept the prepayment estimates proposed by DA customers and CCAs, and

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[37] These resources represent a modest capacity proportion of the Joint Utilities' respective generation portfolios, but on a cost basis, represent 2.3 percent for PG&E (Exhibit IOU-1B, AppF1-1); 11.4 percent for SCE (Exhibit IOU-1B, AppF2-1); and 6.3 percent for SDG&E (Exhibit IOU-1B, AppF3-1).

[38] *Scoping Memo and Ruling of Assigned Commissioners* (September 25, 2017) (Scoping Memo), p. 21.

[39] APD, p. 74.

[40] *Id*.

that the prepayment must instead be based on "a mutually acceptable forecast of that customer's future PCIA obligation."[41]

While the Joint Utilities continue to have concerns regarding the risk to bundled service customers inherent in the prepayment of the PCIA, they acknowledge that the prepayment option provides simplicity and predictability to departing load customers,[42] and may be appropriate in certain instances. Accordingly, the Joint Utilities support the guidelines proposed in the APD, with the limited clarifications described below. The Joint Utilities further note that additional aspects of the prepayment approach must be addressed in Phase II of the instant proceeding and, in any event, prior to execution of any prepayment transaction.

The APD requires that the Joint Utilities negotiate "in good faith" regarding an acceptable PCIA prepayment estimate.[43] The Joint Utilities of course do not object to this good faith requirement, but note that it must be symmetrical. Thus, the APD should be revised to make clear that departing load parties have a corresponding obligation to negotiate in good faith.

In addition, modification of the APD is necessary to prevent potential confusion regarding payment of portfolio costs if a customer departs bundled service, prepays its current PCIA and then returns to bundled service. The APD currently provides that once the prepayment has been made, the departed customer (i) shall not receive a refund if it returns to bundled service; and (ii) may switch among "competitive retail sellers" without incurring any new PCIA obligation.[44] The first scenario applies to departing load customers who prepay their PCIA and then later return to bundled service. Since the PCIA charge is paid only by departing load customers (an equivalent *pro rata* share of portfolio costs is paid by bundled service customers through their generation rate), the second scenario applies to departing load customers who prepay their PCIA and then switch to a different non-IOU retail provider. For the sake of clarity, in addition to specifying that a departing load

[41] *Id*, pp. 71, 73, Ordering Paragraph 7.
[42] *See id*., Finding of Fact (FOF) 22.
[43] APD, p. 73.
[44] *Id*., Ordering Paragraph 7.

customer who returns to bundled service shall not receive a refund of its prepayment, the final decision should make clear that if a departing load customer returns to bundled service, it will pay the same generation rate as other customers in its rate class (irrespective of whether the PCIA in the future becomes a stand-alone rate component for bundled service customers).

The APD should also identify key prepayment issues that must be addressed in Phase II. A critical issue that must be addressed, for example, is the reasonableness benchmarks to be applied in considering prepayment proposals. As TURN correctly points out, "[n]o party has provided a credible set of benchmarks for assessing the reasonableness of a prepayment calculation."[45] While the APD addresses the mechanics and certain conditions that must be met to pursue the prepayment option, it offers no guidance on the important question of how to evaluate the reasonableness of a proposed prepayment amount. Thus, this issue must be taken up in Phase II.

Similarly, the Commission must address in Phase II how to mitigate the impact on other departing load customers of a decision by a DA customer or CCA, on behalf of its customers, to prepay the PCIA. If a DA customer or CCA, on behalf of its customers, prepays the PCIA and the prepayment amount is too low (*i.e.*, it understates the net portfolio cost properly allocated to that DA customer/CCA's customers), the *pro rata* share of net portfolio costs borne by all other customers, including other departing load customers who did not elect to prepay their PCIA, will increase. In other words, prepayment creates the potential for cost shift to remaining bundled service customers ***and*** other departing load customers. Given this fact, the Commission should consider what prospective protections must be put into place for all customers that do not elect to prepay their PCIA prior to authorizing any prepayment.[46] It is important that the protections adopted by the Commission, if any, be applied ***before*** a prepayment is authorized; once the Commission has authorized the prepayment arrangement, after-the-fact review must not be permitted.

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[45] *Reply Brief of [TURN] on Track 2 Issues* (June 15, 2018), p. 35.

VIII. THE APD SHOULD BE REVISED TO INCLUDE IMPROVEMENT IN THE ACCURACY OF DEPARTING LOAD FORECASTS AS A PHASE II ISSUE

Parties in Track 2, most notably CalCCA, expressed dissatisfaction with the Joint Utilities' current approach to forecasting departing load.[47] As discussed at length in the Joint Utilities' testimony and briefing, the Joint Utilities have their own frustrations with the departing load forecast process, stemming, in large part, from the lack of actionable information regarding the timing of both CCA formation and the anticipated load to be served.[48] The Joint Utilities' proposal that the Commission make the submission of a Binding Notice of Intent (BNI) mandatory before a CCA can commence service, or at the very least that stakeholders work together to develop a consensus framework for forecasting departing load, is not addressed in the APD.[49] The APD should be modified to acknowledge that this important issue should be addressed in Phase II of this proceeding.

CalCCA points to a need for improvements to the departing load forecasting process, offering suggestions ranging from the Joint Utilities using "common sense,"[50] to changing the current vintaging rules for resources, to excluding from CCA customers' cost responsibility for contracts executed in a certain year up to the amount of departing load forecast for that year,[51] to requiring the Joint Utilities to file multiple future load-departure scenarios[52] (a process already contemplated in the Commission's Integrated Resource Plan rulemaking).[53] The Joint Utilities respectfully suggest that, rather than seek to impose all forecast risk on remaining bundled service customers, as CalCCA seeks to do, the most fail-safe way to ensure accurate departing load forecasts is for CCAs themselves to provide the Joint Utilities with accurate information regarding the timing and extent of their departures from IOU bundled service. The CCAs,

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47 *See, e.g.*, CalCCA Prepared Testimony, Vol. 2, pp. 3-11 to 3-13.

48 *See, e.g.*, Exhibit IOU-1, pp. 1-19 to 1-21; Joint Utilities Reply Brief, pp. 68-75.

49 *See* Exhibit IOU-3, p. 1-6:3-11; Joint Utilities Reply Brief, p. 75.

50 CalCCA Opening Brief (June 29, 2017), p. 102.

51 *Id*.

52 *Id*., p. 103.

53 *See* D.18-02-018, FOF 9 and Conclusion of Law (COL) 27; *cf.* IEP Opening Brief (June 29, 2017), p. 4 ("Given the existence of rigorous planning and modeling of multiple scenarios over a 10-year timeframe, the Commission should question the added value of and necessity for an additional forum for assessing forecast demand and departing load").

obviously, are in a far superior position than the IOUs to know their own plans. Rather than insisting that the Joint Utilities develop a methodology for divining CCA departure plans with perfect precision, a far more productive practice would be for the CCAs themselves to engage more fully with the task of providing the IOUs – and the Commission—with the requisite information to inform IOU procurement requirements, and then to abide by their departure commitments.

PG&E's current experience with the City of San Jose provides a compelling illustration of the problem. San Jose Clean Energy Community Choice Aggregation (San Jose) was originally scheduled to launch service on April 2, 2018.[54] At some point it decided to delay its launch five months, until September 1, 2018.[55] On March 27, 2018, San Jose provided PG&E with a 2019 load forecast.[56] The load forecast was provided nearly a month after the March 1 voluntary deadline established for CCAs to provide PG&E with their respective load forecasts to permit the forecasts to be incorporated into PG&E's annual ERRA Forecast application filing.[57] But even more problematic than the late submission, the 2019 load forecast San Jose submitted contained the following disclaimer: "San Jose Clean Energy's (SJCE) 2019 forecast is based on current earliest anticipated phased roll-out of customer enrollment and may be subject to change, *and it is not intended to be a binding commitment at this time*."[58] Notably, San Jose, which will be a very large CCA,[59] ***never*** provided PG&E with an updated, reliable 2019 load forecast at any point prior to its September 1 launch.

As an even more recent example, the Joint Utilities take into account in developing their departing load forecasts prospective CCA departures based on RA indications submitted by nascent CCAs in April before the year of their planned departure. But even those RA indications are non-binding and uncertain, and are therefore of little assistance in developing an accurate departing load forecast. For example, Desert Choice Energy (DCE), a CCA in SCE's service

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[54] Evid. Hr. Tr., Vol. 5, p. 987:4-12 (CalCCA, Hoekstra).

[55] *Id*., p. 987:13-25 (CalCCA, Hoekstra).

[56] Ex. IOU-107.

[57] Ex. IOU-106; Evid. Hr. Tr., Vol. 5, pp. 983:24 – 989:7 (CalCCA, Hoekstra). Pursuant to D.16-12-038, CCA submissions of load forecasts to PG&E are voluntary.

[58] Ex. IOU-107, PDF p. 8 (emphasis added).

[59] Evid. Hr. Tr., Vol. 5, p. 990:9-17 (CalCCA, Hoekstra).

territory, submitted an RA load migration filing advising that it would commence service on August 1, 2018. However, DCE subsequently informed SCE **six days** before its launch date, on July 25, 2018, that it would be backing-out of its committed and agreed-upon service date of August 1. This required SCE to readjust its load forecast and continue to procure for and serve those customers until DCE begins service (if ever).

These situations perfectly illustrate the dilemna faced by the Joint Utilities. Which CCA departure dates and load forecasts should the Joint Utilities assume are legitimate and likely, and which should the Joint Utilities instead assume are speculative or aspirational? Will the Commission require nascent CCAs who delay or cancel service departure to reimburse the Joint Utilities for any procurement costs related to those delays or cancellations? Should the Commission instead require that the RA forecast submissions from new CCAs authorized in Resolution E-4907 be financially binding on CCAs, even if they subsequently decide to delay or cancel service? These are just some of the critical questions raised by the current departing load framework.

No constructive answers to these questions were offered by CalCCA or any other party. CalCCA places the burden of correctly forecasting departing load *entirely* on the Joint Utilities – suggesting, as noted above, that the IOUs employ "common sense" to divine the timing and level of load departure – but appears to reject the notion that CCAs bear *any* responsibility at all for providing relevant information to the Joint Utilities, regulators, or the CCA's customers. As a practical matter, this proposed solution is no solution at all. Consistent with their provider-of-last-resort (POLR) responsibilities, the Joint Utilities require more concrete assurances of CCA departures than educated guesses; what CalCCA describes as "common sense" is more accurately described as "Monday morning quarterbacking," as it appears to hold the IOUs to a standard of forecasting that assumes the benefit of facts not in existence at the time of decision-making.

The Joint Utilities already employ "common sense" in their load departure forecasts, but there are obvious limits to the efficacy of this approach. The Joint Utilities respectfully suggest that what would be more productive would be for the CCAs to be *required* to provide the IOU with an *actionable* load forecast in a *timely* manner. It is not just the Joint Utilities that require certainty for planning purposes; customers who are to be defaulted to CCA service should have certainty as to when the default switch is to occur. CCAs should also be required to provide that same information to the CPUC and the California Energy Commission (CEC) to inform those regulators' respective load forecasting processes. Providing CCAs unfettered discretion in this regard is not justified and is contrary to the public interest. Forming CCAs should also be held accountable if their load departure forecasts materially deviate from their actual results.

The current protocol allows CCAs to avoid responsibility for the accuracy of the information they provide – they are not bound by departure date commitments or load forecasts. This creates the potential for unnecessary procurement by the Joint Utilities and impermissible cost-shifting. The Commission has acknowledged the soundness of requiring more concrete assurances of departing load than the filing of an implementation plan. In D.05-12-041, for example, the Commission stated, "[w]e do not agree with Local Power and CCSF that the filing of an implementation plan . . . must automatically trigger changes in utility procurement practices. In some cases, the utility may be able to modify procurement strategies without imposing additional cost or risk on utility customers. As the utilities observe, however, *if the CCA never initiates service, changes in procurement in other cases may ultimately be costly to utility customers*."[60]

The Commission has recognized that it has authority "to designate a CCA's start date with consideration of the impact on the electrical corporation's annual procurement . . ."[61] Indeed, Section 366.2(c)(8) obligates the Commission to "designate the earliest possible effective date for implementation of a community choice aggregation program, *taking into consideration the impact on any annual procurement plan of the electrical corporation that has been approved by the commission*."[62] The Commission has already developed the tool necessary to take all guesswork out of departing load forecasting: the BNI. For the above reasons, the APD should be revised to include in the scope of Phase II consideration of proposals for improvements to the departing load forecast process, including the Joint Utilities' proposal to make the submission of a BNI mandatory before a CCA may commence service.

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[60] D.05-12-041, p. 31 (emphasis added).

[61] Resolution E-4907, p. 3.

[62] Emphasis added.

IX. THE APD SHOULD BE REVISED TO CLARIFY THE SCOPE AND PURPOSE OF PHASE II

A. Portfolio Optimization and Cost Reduction Proposals Developed through the Phase II Workshop Process Should be Considered in the Integrated Resource Plan Rulemaking and/or Other Relevant Commission Proceeding(s)

As the Joint Utilities have observed, the portfolio optimization and cost reduction concepts raised by parties in Track 2 potentially warrant further consideration.[63] The APD reaches a similar conclusion and finds that a second phase of the proceeding involving a "working group" process would facilitate development of such proposals for future consideration by the Commission.[64] As a threshold matter, it is critical that the Commission be cognizant of -- and vigilant concerning -- the customer cost and value propositions that any such "portfolio optimization" proposals will implicate. Collectively, the Joint Utilities' portfolios contain upwards of **$100 billion** of customer cost commitments.[65] Unwinding them will not be simple or cost-free, and any exercise or experiment in doing so should not be undertaken lightly.[66]

In terms of process, the most logical vehicle for considering Phase II proposals for new rules governing the IOUs' market activities, once they have been developed through the workshop process, is the Commission's Integrated Resource Plan (IRP) proceeding, which will focus generally on proposed refinements to the processes and rules governing the IOUs' procurement, as well as changes to the Joint Utilities' respective BPPs. Indeed, the Scoping Memo adopted in the IRP proceeding specifically states that the proceeding will address "[p]rocurement oversight and rules," and activities "associated with…Section 454.5 and the

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63 IOU-3, p.1-1:11-12.

64 APD, p. 78, FOF 24, COL 24.

65 Evid. Hr. Tr., Vol. 1, p. 80:10-15 (Joint Utilities, Wan) (estimating that the Joint Utilities' portfolios combined are "probably in excess of a hundred billion dollars").

66 It is also critical to understand that any portfolio optimization protocols that are developed will not be implemented in a vacuum. Rather, they will be subject to ever-changing policy directives from both the Legislature and the Commission, including the possibility of new procurement mandates. Indeed, as demonstrated by the introduction of AB 893 in the recently-completed session, the Legislature continues to consider imposing significant new renewable procurement mandates on the IOUs. And, of course, the IOUs remain subject to multiple existing procurement mandates that are unrelated to meeting their respective bundled loads.

large IOU bundled procurement plans."[67] An omnibus-type proceeding such as the IRP or, potentially, a separate rulemaking focused on comprehensive changes to rules governing market activities and the IOUs' BPPs, is the appropriate place to consider proposed procurement rule changes developed in Phase II.[68]

Adoption of portfolio reduction or cost optimization proposals developed through the Phase II workshop process will impact how the Joint Utilities manage their respective energy positions, with potentially significant repercussions for California's energy markets, and significant customer cost and portfolio value implications. Implementation of any of the portfolio optimization proposals offered to date would require development of rules for ensuring integrity of market structures and transactions. In addition, implementation would necessitate changes to the existing processes and rules governing the IOUs' procurement activities, as well as to the Joint Utilities' respective RPS plans and BPPs. Thus, the Phase II workshops should feed into and be closely coordinated with the IRP proceeding and/or the separate Commission proceedings that address these same topics so as to avoid redundant work or conflicting outcomes. Moreover, given that the proposals ultimately developed in Phase II could implicate the fundamental underpinnings of the California energy procurement structure, the decision whether to adopt such proposals would likely be of interest to stakeholders beyond those representing departing load interests (*e.g.*, the California Independent System Operator). Thus, the Phase II proposals should be considered in the broader context of a Commission rulemaking focused on rules governing market activity and the procurement framework as a whole, rather than in the narrow context of this proceeding.

In addition, and consistent with the State's foundational post-Energy Crisis procurement policy regime as established in AB 57 and codified in Section 454.5, the APD should be revised to expressly state that Phase II will focus exclusively on going-forward portfolio optimization

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67 R.16-02-007, *Joint Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge* (May 26, 2016), p. 12.

68 Proposals developed through the Phase II workshop process may, at the sole discretion of the Joint Utilities, be included in the proposed BPPs filed by the Joint Utilities in the context of the IRP proceeding (or separate proceeding focused on comprehensive updates to the BPP), or proposed by stakeholders in responsive comments filed in the IRP proceeding (or separate relevant proceeding) regarding the Joint Utilities' proposed BPPs.

activities, and will not revisit past procurement decisions approved by the Commission via Advice Letter, Application, or consistent with pre-approved procurement plans (*e.g.*, the BPP (as reported through Quarterly Compliance Report (QCR) filings) or the RPS Plan). Any other result would violate both state law and sound public policy.

Finally, the APD's conclusion that "Commercial Energy's Voluntary Allocation & Auction Clearinghouse [VAAC] proposal should be further developed in a second phase of this proceeding" should be stricken.[69] As discussed above, the Joint Utilities support the exploration of portfolio optimization and cost reduction in workshops, but note that the body of evidence in this proceeding does not support a preference for any of the portfolio optimization alternatives proposed in the proceeding over other alternatives. If anything, it is logically incongruent for the APD to "render moot the questions of statutory interpretation"[70] for categorization of PCC 1 RECs under the Joint Utilities GAM/PMM proposal, while preferentially supporting the VAAC proposal, which requires the same statutory conclusion.[71] Accordingly, the specific reference to further development of Commercial Energy's VAAC proposal should be deleted from the final decision; the VAAC proposal is one of several options to be explored in Phase II and the APD should not pre-judge its merit.

Thus, the objective of Phase II should be to further develop portfolio reduction and cost optimization proposals, and to achieve consensus, with support from Commission staff, regarding structures, processes, and rules governing potential additional bundled service portfolio optimization activities going forward. As discussed above, once the working group process has been completed, proposals for refinements of procurement processes and rules, and for BPP modifications necessary to implement agreed-upon portfolio reduction measures, would be submitted for Commission approval in the IRP proceeding, in a new rulemaking focused on comprehensive revisions to rules governing market activity and the IOUs' BPPs, or in a separate relevant proceeding.

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[69] *See* APD, COL 8.

[70] *Id*., p. 77.

[71] Evid. Hr. Tr., Vol. 5, pp. 1049:16-1050:23 (Commercial Energy, Perry).

B. The Scope of Phase II Should be Expanded to Address Development of Departing Load Forecasting Proposals and Resolution of Unresolved Issues Related to the Prepayment Option

As discussed herein, in addition to further developing proposals related to portfolio optimization and cost reduction, Phase II should focus on development of: (1) proposals regarding a departing load forecast methodology; and (2) unresolved issues related to the prepayment option. Attachment A proposes revisions that would include these important issues within the scope of Phase II.

X. CONCLUSION

For the reasons set forth above, the APD should be revised consistent with the discussion herein and the proposed language revisions set forth in Attachment A hereto, and adopted by the Commission as its final decision in this proceeding.

Respectfully submitted this 6th day of September, 2018.

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ATTACHMENT:

Attachment A – Proposed Findings of Fact, Conclusions of Law and Ordering Paragraphs; Proposed Revised Appendix 1

Attachment A

Proposed Findings of Fact, Conclusions of Law and Ordering Paragraphs; Proposed Revised Appendix 1

Attachment A

Findings of Fact

1. The Commission's current PCIA methodology cannot prevent cost shifts between customers. **When the PCIA methodology underestimates the PCIA obligation, costs are shifted to bundled service customers. When the PCIA methodology overestimates the PCIA obligation, costs are shifted to departing load customers.**

2. AReM/DACC demonstrated in testimony that the current methodology for calculating the Brown Power Index produces acceptable estimates **for setting forecast PCIA rates effective in each year, but would be improved by weighting on-peak and off-peak energy pricing by supply instead of demand. The resulting Brown Power Index benchmark must be trued up in the following year to reflect actual net revenues realized in the CAISO markets by recording the generation resources' net CAISO market revenues received to the resources' respective PABA vintaged subaccount.**

3. A revised RPS Adder that is calculated using the reported prices of purchases and sales of renewable energy by the IOUs, **CAs,** CCAs and ESPs will produce reasonably accurate estimates **for setting forecast PCIA rates effective in each year. The RPS Adder must be trued-up in the following year to reflect the actual market value of Renewable Energy Credits (RECs) in the IOUs' portfolios that are not used to satisfy the RPS compliance requirements of the IOUs' remaining bundled service customers for that same year, including a zero-dollar revenue assigned for RECs that remain unsold or are banked in that same year.**

4. A revised RA Adder that is calculated using reported purchase and sales prices of IOU, CCA, **CA** and ESP transactions will produce reasonably accurate estimates **for setting forecast PCIA rates effective in each year.** ~~if a zero or de minimis price is assigned for capacity expected to remain unsold~~ **The RA Adder must be trued-up in the following year to reflect the actual market value of RA in the IOUs' portfolios that is not used to satisfy the RA compliance requirements of the IOU's remaining bundled service customers, including a zero-dollar value assigned for capacity that remained unsold.**

5. The revised RA Adder will be more accurate if it is calculated in a manner that reflects the three types of RA capacity: system, local, and flexible**, and is subject to true-up**.

6. The RPS Adder would be more accurate if it was calculated with additional transaction reporting data from CCAs**, CAs** and ESPs**, and is subject to true-up.**

7. Calculations in Exhibit AD-02 indicate that the GAM/PMM proposal of the Joint Utilities ~~w~~**c**ould be significantly more impactful on customer choice in the SDG&E territory, compared to its impact in the PG&E or SCE territories.

8. Allocating RECs to an LSE without providing the associated energy is not identical to a forward sale of bundled renewable energy.

9. CalCCA has not provided evidentiary support that the new "administrative benchmarks" that it proposes are ~~the most~~ reasonable proxies for portfolio valuation.

10. It is not practical to attempt to implement voluntary allocation and auction mechanisms by January 2019.

11. The RA Adder and RPS Adder methodologies proposed by AReM/DACC are feasible, but better proposals have been recommended in this proceeding.

12. Legacy UOG is utility-owned generation installed before 2002.

13. CCA customers have benefited from Legacy UOG and reliability benefits of Legacy UOG continue to accrue to CCA customers, as well as bundled service and DA customers.

14. Post-2002 UOG is **fossil-fueled** utility-owned generation installed after 2002 **for all three IOUs and solar utility-owned generation installed after 2002 for PG&E only**.

15. The Commission has mandated that the utilities procure resources through programs such as the Renewable Market Adjusting Tariff (ReMAT), the Bioenergy Market Adjusting Tariff (BioMAT) and Renewable Auction Mechanism (RAM) to meet policy goals, irrespective of whether the procurement is needed to serve bundled service customer load. The Commission's Public Utility Regulatory Policies Act (PURPA) program requires the utilities to procure resources through the

program, irrespective of whether the procurement is needed to serve bundled service customer load.

16. The pro rata above-market costs of such mandated procurement is currently recovered from departing load customers through the PCIA, subject to vintaging rules.

17. The revenue allocation factors for vintaged Indifference Amounts used by PG&E, SCE and SDG&E are not consistent with the factors used to allocate the same generation costs to their bundled service customers.

18. A true-up mechanism **for all three benchmarks – the Brown Power Index, RPS Adder and RA Adder – to reflect actual values realized in market transactions for the subject year, including zero-dollar value for any unsold attributes not used for bundled service customer compliance needs, is necessary to maintain customer indifference, and** will ensure that bundled and departing load customers pay ~~equally~~ **equitably (i.e., pro rata)** for PCIA-eligible resources.

19. The Joint Utilities demonstrated in testimony that departing load has resulted in, or may eventually result in, the Joint Utilities having RPS attributes that are in excess (i.e. "long") of the RPS attributes necessary to satisfy the RPS compliance requirements of the Joint Utilities' remaining bundled service customers.

20. The terms and conditions for IOU transactions of Bundled or Unbundled Renewable Energy Credits (RECs) are set forth in each IOU's respective Renewable Portfolio Standard (RPS) Procurement Plans and/or Bundled Procurement Plans (BPPs), which are subject to the Commission's approval.

21. The ratemaking proposal in Exhibit IOU-1 provides general concepts that can be used to implement an annual true-up process for the PCIA.

22. A ~~PCIA~~ collar **on the PCIA rate** with a floor and a cap ~~will limit the change of the PCIA from one year to the next~~ **fails to prevent cost shifts.**

23. In 2007, Commission Resolution E-3999 ~~directed~~ **permitted** the IOUs to offer bilateral agreements to publicly-owned utilities (with departing load customers) as an alternative to the Municipal Departing Load tariff.

24. PG&E, SCE and SDG&E each have a "New Municipal Departing Load" tariff that includes the option to pay the PCIA and other departing load obligations as a negotiated lump sum.

25. The record evidence cited by the Joint Utilities does not support their assertion that requiring them to accept a prepayment estimate of a customer's long-term cost responsibility would shift substantial risks to remaining bundled service customers.

26. **Certain departing load customers may wish to** ~~P~~**p**repay~~ments~~ **their** ~~of~~ PCIA obligations ~~will serve as a longer-term measure to reduce the size of the Joint Utilities' PCIA portfolios.~~ **in order to end their obligation at an earlier point.**

27. An option to prepay would provide simplicity and predictability for **those** departing load customers **who elect prepayment**.

28. The record in this proceeding indicates that allocation and auction mechanisms **may** offer realistic and promising approaches to utility portfolio optimization and cost reduction**, but require further development**.

29. A new phase of this proceeding would enable parties to continue working together to **(1) develop proposed improvements to the departing load forecast process; (2) address the unresolved issues identified herein related to the prepayment option; and (3)** develop ~~a number of~~ proposals regarding portfolio optimization and cost reduction for future consideration by the Commission.

Conclusions of Law

1. The Commission's current PCIA methodology leads to outcomes that are inconsistent with the requirements of Sections 365.2**, 366.2** and 366.3 **of** ~~to~~ the Public Utilities Code, and should be revised as specified in this decision.

2. The methodology for calculating the Brown Power Index adopted in D.06-07-030 should **be largely kept intact, but (1) should be weighted according to on-peak and off-peak supply instead of demand, and (2) must be trued-up to reflect net energy and ancillary service revenues received in the CAISO markets in the subject year.** ~~not be changed~~.

3. The methodology for calculating the RPS Adder adopted in D.11-12-018 should be changed to the method provided in Appendix 1 of this decision **and should include a**

true-up to reflect the actual market value of any RECs in the IOUs' portfolios that are not used to satisfy the RPS compliance requirements of the IOUs' remaining bundled service customers for the subject year.

4. The methodology for calculating the RA Adder adopted in D.06-07-030 and modified in D.07-01-030 should be changed to the method provided in Appendix 1 of this decision **and should include a true-up of any RA in the IOUs' portfolios that is unsold and not used to satisfy the RA compliance requirements of the IOUs' remaining bundled service customers for the subject year at zero dollars**.

5. The Commission should establish new transaction reporting requirements for **CAs,** CCAs and ESPs to ensure that the RPS Adder is as accurate as possible.

6. It is not necessary to require ESPs and CCAs to accept allocations of RA and RPS attributes in order to prevent cost shifting between bundled load customers and departing load customers.

7. The RA Adder and RPS Adder methodologies proposed by CalCCA should not be adopted.

8. ~~Commercial Energy's Voluntary Allocation & Auction Clearinghouse proposal should be further developed in a second phase of this proceeding.~~

9. The RA Adder and RPS Adder methodologies proposed by AReM/DACC should not be adopted.

10. The Legislature intended, in AB 117, "to prevent any shifting of recoverable costs between customers."

11. In SB 350, the Legislature directed that "[b]undled retail customers of an electrical corporation shall not experience any cost increase as a result of the implementation of a community choice aggregator program. The commission shall also 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."

12. The year before passing AB 117, in ABx1-6, the Legislature required retention of Legacy UOG under cost-of-service regulation until Commission-approved disposition of the Legacy UOG.

13. **A reasonable reading of AB 117 provides for the recovery of Legacy UOG as "additional costs of the electrical corporation recoverable in Commission-approved rates."**

14. Principles of statutory construction require reading and considering a statute as a whole to ensure that the true legislative intent is determined.

15. Since 2004, Commission decisions implementing legislative directives to prevent cost shifts included recovery of costs of pre-2002 Legacy UOG from CCA customers.

16. Including the costs of pre-2002 Legacy UOG within the PCIA is consistent with **ABx1-6,** AB 117**,** ~~and~~ SB 350 **and prior Commission decisions**.

17. There is no justification to continue a 10-year limit on recovering costs for post-2002 UOG from departing load, a limitation that does not exist for post-2002 PPAs or for pre-2002 UOG.

18. PCIA-eligible energy storage resources will be treated the same as other resources in the IOU portfolio, and will not be subject to a 10-year limitation on **cost** recovery.

19. Mandated RPS and PURPA procurement benefits all customers equally and therefore the net costs of such procurement should be paid for by all customers pro rata, and such procurement should not be subject to PCIA vintaging rules.

20. The revenue allocation factors for vintaged Indifference Amounts should be consistent with the factors used to allocate generation costs to their bundled service customers.

21. A true-up mechanism **for all three benchmarks – the Brown Power Index, RPS Adder and RA Adder – to reflect actual values realized in market transactions for the subject year, including zero-dollar value results for any unsold attributes,** should be adopted to ensure that bundled and departing load customers pay **equitably (i.e., pro rata)** ~~equally~~ for PCIA-eligible resources.

22. To the extent that an IOU has RECs that are not used to satisfy the RPS compliance requirements of its remaining bundled service customers, in order to determine and maximize their value, the IOU shall attempt to monetize such excess RECs in a manner consistent with the IOU's approved RPS Plan and BPP.

23. **<u>For calculating the final true-up value of the relevant RPS attributes, the actual revenues received for REC products sold should be credited on a pro rata basis to the PABA's vintaged subaccounts as an offset to overall vintaged portfolio costs. To the extent that any RPS attributes are not able to be sold, they should be credited at a zero-dollar value for purposes of the PCIA true-up.</u>**

24. PG&E, SCE and SDG&E should each establish a Portfolio Allocation Balancing Account with ~~three~~ subaccounts **<u>for each vintage</u>** to account for the costs and revenues associated with the Brown Power**<u>, Renewable Energy, and RA Capacity in each vintaged portfolio.</u>** ~~Index, the RPS Adder and the RA Adder.~~

25. The Commission should not adopt a sunset of the obligation to pay the PCIA.

26. A PCIA collar with a floor and a cap should **<u>not</u>** be adopted**<u>.</u>** ~~to limit the change of the PCIA from one year to the next.~~

~~27. Starting with forecast year 2020, the floor of the PCIA collar should be permanently set at 75% of the prior year's PCIA.~~

~~28. Starting with forecast year 2020, the cap level of the PCIA collar should be set at 125% of the prior year's PCIA.~~

~~29. Each utility should establish an interest-bearing balancing account that shall be used in the event that the cap is reached to track any obligation that accrues for departing load customers. Any balances in the account should earn interest at the same rate earned by balances in the ERRA balancing account. The year-end balances in the balancing accounts should be incorporated into the PCIA calculation for the following year.~~

27. DA customers and CCAs, on behalf of their customers, should be permitted to pre-pay their PCIA obligations, subject to **<u>a negotiated, agreed-upon bilateral agreement with the IOU and</u>** Commission approval on a case-by-case basis **<u>and factors to be developed in a second phase of this proceeding</u>**.

28. A second phase of this proceeding should be opened in order to ~~consider proposals for a "working group" process to~~ enable parties to continue working together **<u>using a "working group" process</u>** to **<u>(1) develop proposed improvements to the departing load forecast process; (2) address the unresolved issues identified herein related to the prepayment option; and (3)</u>** develop proposals regarding portfolio optimization and

cost reduction for future consideration by the Commission.

29. **<u>IOU procurement activities approved by the Commission via application, advice letter, or consistent with a pre-approved procurement plan (e.g., BPP, RPS Plan) and in compliance with those plans are not subject to after-the-fact reasonableness review.</u>**

30. **<u>Consistent with AB 57 and Section 454.5 of the Public Utilities Code, any portfolio optimization and cost reduction proposals considered in a second phase of this proceeding must be forward-looking and must not revisit the reasonableness of procurement decisions previously approved by the Commission via application, advice letter, or through a pre-approved procurement plan (e.g., BPP, RPS Plan).</u>**

O R D E R

IT IS ORDERED that:

1. The Commission's Energy Division shall calculate the following values and make them available to interested parties at the beginning of November each year: (1) the Brown Power Index, (2) the renewable procurement standard (RPS) Adder, and (3) the resource adequacy (RA) adder**<u>, in order to set PCIA rates for the following year:</u>**

   a. The Brown Power Index shall continue to be calculated using the methodology adopted in Decision (D.) 06-07-030 **<u>(subject to the modifications reflected in Appendix 1 hereto)</u>**.

   b. The RPS Adder shall be calculated using reported prices from purchases and sales of renewable energy by the investor-owned utilities (IOUs), **<u>Community Aggregators (CAs),</u>** Community Choice Aggregators (CCAs) and ESPs during the year two years prior to the forecast year (year n-2) for delivery in the forecast year (year n). For the 2019 RPS Adder forecast only, the Energy Division shall use the most recently published Platts Portfolio Content Category (PCC) 1 REC index mid value ("California Bundled REC (Bucket 1)") as of November 1, 2018. The RPS Adder for each utility will be the sum of the Platts PCC 1 REC index value and its brown power index.

   c. The RA Adder shall be calculated using reported purchase and sales prices from IOU, **<u>CA,</u>** CCA, and Electric Service Provider(ESP) transactions made during (year n-1) for deliveries in (year n). A zero**<u>-dollar</u>** ~~or *de minimis*~~ price shall be assigned for capacity expected to remain unsold. The RA Adder shall be calculated in a manner that reflects the three types of RA capacity: system, local, and flexible. For the 2019 RA Adder only, the Energy Division shall use the weighted average system and local RA prices in the most recent annual **CPUC** RA report**, including consideration of capacity expected to remain unsold.**

2. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall calculate their respective PCIA rate that takes effect January 1 of each year using the values for the Brown Power Index, the Renewables Portfolio Standard Adder, and the Resource Adequacy adder that have been calculated pursuant to Ordering Paragraph 1.

3. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company, shall annually true-up their PCIA rates to reflect actual values realized in market transactions for the subject year for the Brown Power Index, the RPS Adder and the RA Adder, including zero-dollar values for any unsold attributes. The RPS Adder shall be trued-up to reflect the actual market value of RECs in the IOUs' portfolios that are not used to satisfy the RPS compliance requirements of the IOUs' remaining bundled service customers for that same year.

4. To the extent that the IOUs have RECs that are not used to satisfy the RPS compliance requirements of the IOUs' bundled service customers, in order to determine and maximize their value, Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company shall attempt to monetize them in the following way:

   a. The IOU shall conduct regular sales of Bundled and Unbundled REC products on a prospective basis. Both long-term (i.e., 10 years or longer), and short-term products shall be offered, subject to terms and conditions and any regulatory requirements set forth in the IOU's RPS Plan and/or BPP.

b. **To the extent that products offered are not successfully sold on a prospective basis before being generated, the IOU shall conduct regular solicitations for the sale of short-term PCC-3-eligible RECs generated by the resources.**

c. **Within 36 months of the initial date of the associated generation, any RECs that remain unsold, consistent with current statute, shall be transferred to the IOU's WREGIS account and shall retain their original PCC designation for remaining bundled service customers for CPUC compliance purposes.**

d. **For calculating the final true-up value of the relevant RPS attributes, the actual revenues received for REC products sold shall be credited on a pro rata basis to the PABA's vintaged subaccounts as an offset to overall vintaged portfolio costs.**

e. **To the extent that any RPS attributes offered for sale are not sold, the unsold attributes shall retain a zero-dollar value for purposes of the PCIA true-up.**

5. **All LSEs' RA and RPS transactions shall be reported to the Commission for inclusion in the subsequent year's benchmark calculation.**

6. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall **propose in their respective General Rate Case Phase II applications to** modify the revenue allocation factors for vintaged Indifference Amounts to be consistent with the factors used to allocate generation costs to their bundled service customers.

7. The Commission establishes new transaction reporting requirements for all Load-Serving Entities, including Community Choice Aggregators and Energy Service Providers, to ensure that the Renewables Portfolio Sstandard Adder is as accurate as possible. Beginning in 2019, all Load-Serving Entities shall submit the information

listed below to the Commission's Energy Division on an annual basis by January 31. We adopt the following additional requirements:

- Contract information shall be collected for all Load-Serving Entity contracts executed in year n-2, with year n being the forecast year for which the Power Charge Indifference Adjustment calculation is being done.
- Contract information shall include: seller name, execution date, contract price ($/MWh), term length of contract, capacity (MW), associated Net Quantifying Capacity, annual expected generation (MWh/year), expected generation for year n.
- If a contract includes Time of Delivery (TOD) adjustments, then the contract's price shall be TOD-adjusted.

8. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall each file a Tier 2 Advice Letter **within 60 days** to establish a Portfolio Allocation Balancing Account (PABA) with ~~three~~ subaccounts **for each vintaged portfolio** to account for **billed revenues**, ~~the~~ **generation resource** costs, ~~and~~ **net CAISO market** revenues associated with **energy and ancillary services, and** ~~the brown power index, the R~~ **revenues associated with the r**enewable **energy** ~~Portfolio Standard~~ Adder and the Resource Adequacy ~~Adder~~ **capacity in each vintaged portfolio**. Each utility shall also modify its Energy Resource Recovery Account (ERRA) balancing account and any other balancing accounts, as necessary, to be consistent **with** the PABA **vintaged subaccount** structure adopted in this decision. Any year-end undercollection or overcollection in the **vintaged** PABA **subaccounts** shall be incorporated into the **vintaged** Power Charge Indifference Adjustment rate calculation in the following year, as part of each utility's ERRA forecast proceeding. The accuracy of the entries in the **vintaged** PABA ~~and its~~ subaccounts shall be reviewed in each utility's annual ERRA compliance proceeding.

~~9. A Power Charge Indifference Adjustment (PCIA) collar with a floor and a cap is adopted and shall be structured as specified below:~~

~~a. Starting in forecast year 2020, the floor of the PCIA collar is set at 75% of the prior year's PCIA.~~

~~b. Starting in forecast year 2020, the cap level of the PCIA collar is set at 125% of the prior year's PCIA.~~

~~c. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall each file a Tier 2 advice letter to~~

~~establish an interest-bearing balancing account that shall be used in the event that the cap is reached, in order to track any obligation that accrues for departing load customers. Any balances in the account should earn interest at the same rate earned by balances in the Energy Resource Recovery Account balancing account.~~

~~d. The year-end balances in the balancing accounts established pursuant to sub-paragraph (d) above shall be incorporated into the PCIA calculation for the following year.~~

9. Direct Access customers and Community Choice Aggregators, on behalf of their customers, shall be permitted to pre-pay their Power Charge Indifference Adjustment (PCIA) obligations, which shall be determined within the following framework:

e. The prepayment **shall be conditioned upon development of** ~~shall be based on~~ a mutually-acceptable forecast of that customer's future PCIA obligation;

f. The prepayment ~~may~~ shall take the form **mutually agreed-to by the parties to the prepayment arrangement** ~~either (1) a one-time payment; or (2) a series of levelized payments over 2-5 years~~;

g. The prepayment shall not be trued-up at a later date;

h. Once the prepayment has been made, the customer shall not receive any refunds if it returns to bundled service**. A customer who returns to bundled service will pay the same generation rate as other customers in its rate class**; and

i. After prepayment is finalized, the customer may switch among **non-IOU** competitive retail sellers without incurring any new PCIA obligation.

10. Any prepayment agreement reached between counterparties pursuant to Ordering Paragraph **8**~~6~~ of this decision shall be submitted for Commission approval by the utility counterparty **in** an application.

11. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall each file a Tier 2 advice letter **within 60 days** to establish a balancing account to record all prepayments of Power Charge Indifference Adjustment obligations received pursuant to agreements reached pursuant to Ordering Paragraph **8**~~6~~ of this decision. Each utility shall describe its proposed disposition of the balances in these accounts in its advice letter.

12. A second phase of this proceeding is opened in order to establish a "working group" process to enable parties to **(1) develop proposed improvements to the departing load forecast process; (2) address the unresolved issues identified herein related to the prepayment option; and (3)** ~~further~~ develop **forward-looking** ~~a number of~~ **portfolio optimization and cost reduction** proposals**.** ~~for future consideration by the Commission~~. **Portfolio optimization and cost reduction proposals developed through the Phase II workshop process may, at the sole discretion of the Joint Utilities, be included in the proposed BPPs filed by the Joint Utilities, or proposed by stakeholders in responsive comments filed regarding the Joint Utilities' proposed BPPs.** A prehearing conference shall be scheduled to initiate that process.

13. Rulemaking 17-06-026 remains open. This order is effective today.

Dated_____________________________, at San Francisco, California

<u>**Appendix 1 (Revised – CLEAN)**</u>

Revised Formula for the Power Charge Indifference Adjustment (PCIA) Calculation

<u>Definition of Terms:</u>

- BROWN = Brown Power Index
- RPS = RPS Adder
- RA = RA Value
- n = PCIA forecast year covered by the calculation (e.g. n=2020 for 2020 forecast year)
- v = PCIA vintage year
- NQC = Net Qualifying Capacity (MW)

<u>Adopted Formula:</u>

The MPB for energy in year n for Vintage Total Portfolio v:

MPB v/n = { (1-RPS% v/n) x BROWN + (RPS% v/n) x (RPS Adder + BROWN) }

Market Value v/n = MPB v/n x (Brown Energy v/n + RPS Energy v/n) + (NQC v/n x RA)

Indifference Amount v/n = Portfolio Costs v/n – Market Value v/n + TRUE-UP v/n-1

Where TRUE-UP v/n-1 is the result of true-up of portfolio costs, market revenues and PCIA revenues from customers responsible for Vintage Total Portfolio v in the prior year. TRUE-UP v/n-1 will be negative in the case of an over-collection in the PABA subaccount for vintage v and will be positive in the case of an under-collection in the PABA subaccount for vintage v.

PCIA v/n (for rate group i) = (Indifference Amount v/n x allocation factor for rate group i) / Forecast kWh usage of customers in rate group i responsible for Vintage Total Portfolio v[1]

Data Sources

1. Brown Power Index ($/MWh) = Weighted average of peak and off-peak forward energy prices for year n, weighed based on, for each IOU, the production profile of resources in the Vintage Total Portfolio v in year n. Peak and off-peak forward energy prices based on published data for NP15/SP15 pursuant to D.06-07-030 RPS Adder ($/MWh) = weighted average of non-utility-only mandated RPS procurement costs excluding RA value from all Load Serving Entities (LSEs) for purchase and sales transactions in year n-2, reported in year n-1 and trued-up in year n+1 less the Brown Power Index.
2. RA Value ($/KW-year) = weighted average of system, local and flexible RA prices from all Load Serving Entities (LSEs) for purchases and sales transactions in year n-2 as published in the annual RA report by the Commission's Energy Division

Illustrative Numerical Example for a Particular Vintage

Peak forward energy price = 6 cents/kWh

Off-peak forward energy price = 4 cents/kWh

Proportion of portfolio output produced in peak period = 30%

Proportion of portfolio output produced in the off-peak period = 70%

BROWN = (6 x .3) + (4 x .7) = 4.6 cents/kWh

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[1] For simplicity, the formulas in this appendix and the numerical example below assumes a Competition Transition Charge (CTC) of zero. When the CTC is non-zero, it will be subtracted from the Indifference Rate to determine the PCIA.

Weighted average of RPS procurement costs excluding RA value from all LSEs = 5.6 cents/kWh

RPS Adder = 5.6 – 4.6 = 1 cents/kWh

RA Value = $30/kW-year

RPS % = 33%

MPB = [(1 - .33) x 4.6] + [.33 x (4.6 + 1)] = 4.93 cents/kWh

Total energy (Brown plus RPS) produced by the portfolio = 5 billion kWh

NQC = 700,000 kW

Market Value = (4.93 cents/kWh x 5 billion kWh) + (30/kW x 700,000 kW) = $267.5 million

Portfolio Costs = $350 million

True-up from the previous period = $20 million

Indifference Amount = 350 – 267.5 + 20 = $102.5 million

Allocation factor for rate group i = 40%

Forecast kWh usage by rate group i responsible for the vintaged portfolio = 1.5 billion kWh

PCIA = (.4 x 102.5)/1.5 billion kWh = 2.733 cents/kWh

End of Appendix 1

<u>Appendix 1 (Revised)</u>

Revised Formula for the Power ~~Cost~~ <u>Charge</u> Indifference Adjustment (PCIA) Calculation

~~Market Price Benchmark (MPB)~~

<u>Definition of Terms:</u>

- BROWN = Brown Power Index
- RPS = RPS Adder
- RA = RA ~~Adder~~ **<u>Value</u>**
- n = PCIA forecast year covered by the calculation (e.g. n=2020 for **<u>2020 forecast year)</u>** ~~MPB for 2020 forecast year)~~
- v = PCIA vintage year
- NQC = Net Qualifying Capacity (MW)

<u>Adopted Formula:</u>

The MPB for **<u>energy in</u>** year n **<u>for</u>** Vintage Total Portfolio ~~V~~**<u>v:</u>**

<u>MPB v/n</u> = { (1-RPS% **<u>v/n</u>**) x **<u>BROWN</u>** ~~Brown Adder~~ + (RPS% **<u>v/n</u>** ~~V~~) x **<u>(</u>**RPS Adder + **<u>BROWN)</u>** }

~~RA Adder V } x (LOSSES)~~

Market Value ~~V~~ **<u>v/n</u>** = MPB ~~V~~ **<u>v/n</u>** x (Brown Energy ~~V~~ **<u>v/n</u>** + RPS Energy ~~V~~ **<u>v/n</u>**) **<u>+ (NQC v/n x RA)</u>**

<u>Indifference Amount v/n = Portfolio Costs v/n – Market Value v/n + TRUE-UP v/n-1</u>

<u>Where TRUE-UP v/n-1 is the result of true-up of portfolio costs, market revenues and PCIA revenues from customers responsible for Vintage Total Portfolio v in the prior year.</u>

TRUE-UP v/n-1 will be negative in the case of an over-collection in the PABA subaccount for vintage v and will be positive in the case of an under-collection in the PABA subaccount for vintage v.

PCIA v/n (for rate group i) = (Indifference Amount v/n x allocation factor for rate group i) / Forecast kWh usage of customers in rate group i responsible for Vintage Total Portfolio v[1]

~~Or~~

~~Market Value V = (Brown Energy V x Brown Adder + RPS Energy V x RPS Adder + NQC V x RA Adder) x (LOSSES)~~

Data Sources

1. Brown Power Index ($/MWh) = Weighted average of peak and off-peak forward **energy** prices for year n, weigh**ed**~~ting~~ based on, for each IOU, ~~the IOU bundled load~~ **the production** profile **of resources in the Vintage Total Portfolio v in year n.** ~~data for the most recent year that is publicly available.~~ Peak and off-peak forward **energy** prices based on published data for NP15/SP15 pursuant to D.06-07-030
2. RPS Adder ($/MWh) = weighted average of **non-utility-only mandated** RPS procurement costs excluding RA value from all Load Serving Entities (LSEs) for purchase and sales transactions in year n-2, reported in year n-1 and trued-up in year n+1 **less the Brown Power Index**.

[1] **For simplicity, the formulas in this appendix and the numerical example below assumes a Competition Transition Charge (CTC) of zero. When the CTC is non-zero, it will be subtracted from the Indifference Rate to determine the PCIA.**

3. RA **Value** ~~Adder~~ ($/KW-year) = weighted average of system, local and flexible RA prices from all Load Serving Entities (LSEs) for purchases and sales transactions in year n-2 as published in the annual RA report by the Commission's Energy Division

Illustrative Numerical Example for a Particular Vintage:

Peak forward energy price = 6 cents/kWh

Off-peak forward energy price = 4 cents/kWh

Proportion of portfolio output produced in peak period = 30%

Proportion of portfolio output produced in the off-peak period = 70%

BROWN = (6 x .3) + (4 x .7) = 4.6 cents/kWh

Weighted average of RPS procurement costs excluding RA value from all LSEs = 5.6 cents/kWh

RPS Adder = 5.6 – 4.6 = 1 cents/kWh

RA Value = $30/kW-year

RPS % = 33%

MPB = [(1 - .33) x 4.6] + [.33 x (4.6 + 1)] = 4.93 cents/kWh

Total energy (Brown plus RPS) produced by the portfolio = 5 billion kWh

NQC = 700,000 kW

Market Value = (4.93 cents/kWh x 5 billion kWh) + (30/kW x 700,000 kW) = $267.5 million

Portfolio Costs = $350 million

True-up from the previous period = $20 million

Indifference Amount = 350 – 267.5 + 20 = $102.5 million

<u>Allocation factor for rate group i = 40%</u>

<u>Forecast kWh usage by rate group i responsible for the vintaged portfolio = 1.5 billion kWh</u>

<u>PCIA = (.4 x 102.5)/1.5 billion kWh = 2.733 cents/kWh</u>

End of Appendix 1