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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 THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON ASSIGNED COMMISSIONER'S ALTERNATE PROPOSED DECISION

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Pursuant to Rule 14.3 of the California Public Utilities Commission (CPUC) Rules of Practice and Procedure, and the August 20, 2018, e-mail ruling of Administrative Law Judge Roscow, the California Community Choice Association (CalCCA) submits these comments on the Alternate Proposed Decision of Assigned Commissioner Peterman (APD).

I. INTRODUCTION AND SUMMARY

The APD would inflict a material cost shift on Community Choice Aggregation (CCA) load customers, stemming from the APD's treatment of utility-owned generation (UOG) and its valuation of attributes in the Joint Utilities' portfolios. According to the Joint Utilities' own data[1], the APD will increase system average PCIA rates 17 percent for Pacific Gas and Electric (PG&E) and 42 percent for Southern California Edison Company (SCE), relative to 2019 Resource Recovery Account (ERRA) forecast rates. The changes to the benchmarks underlying these increases will leave CCAs, if they survive, unable to procure power for their customers at the supply cost implied by the APD for the utility's bundled customers.[2] The APD thus will translate into significant rate increases for CCA customers across the state, while the utilities' bundled customers will benefit from a rate decrease.

The APD drives this striking imbalance by ignoring clear statutory directives, undervaluing the benefits of the utilities' portfolios and generally straining public policy in several ways. The APD:

1 Workpapers distributed by the Joint Utilities on August 31, 2018.
2 "Implied cost" means the bundled generation rate, less the PCIA rate and the generation-related administrative and general costs.

- Imposes pre-2002 "Legacy" UOG on CCA departing load customers, (1) contravening applicable law, (2) allowing recovery of avoidable costs, (3) nullifying a previous agreement that balanced bundled and departing customer interests, (4) protecting the Joint Utilities' shareholders from the effects of changes in the regulatory environment signaled years ago and (5) shifting the costs of uneconomic operating costs and new capital investments to departed customers, contrary to the Commission's indifference standards.

- Removes the 10-year limitation on PCIA recovery of post-2002 UOG costs, ignoring prior Commission decisions and dilutes the incentives for the Joint Utilities to prudently manage their portfolios.

- Scrapes the bottom of the barrel in proposing a flawed, short-term RA capacity benchmark, based on a limited data set, to value 100 percent of the Joint Utilities' portfolio capacity, leaving CCAs no alternative but to procure in the short-term market to compete with the Joint Utilities.

- Lacks clarity in defining the proposed annual "true-up," reducing certainty, stability and predictability of the PCIA, contrary to Scoping Memo Principle 1.b.

- Fails to adopt – or even to consider – a premium to reflect the growing value of greenhouse gas (GHG)-free resources, essentially equating the value of brown and GHG-free power.

- Proposes a PCIA rate increase collar that will serve little, if any, purpose.

In these ways, the APD creates a bleak environment for community choice aggregation, impairing CCAs' abilities to accelerate the state's decarbonization and economic justice policy goals and to adequately meet the needs of the local communities they serve.

CalCCA requests that the Commission correct the APD's errors through the following changes: (1) exclude Legacy UOG costs from CCA departing load charges, consistent with applicable law; (2) retain the 10-year limitation on post-2002 UOG cost recovery; (3) clarify that only costs and revenues, not the market price benchmark, will be subject to an annual true-up; (4) if the Commission rejects long-term values, modify the capacity benchmark to reflect a more reasonable short-term value using CalCCA's proposed weighted benchmark or, alternatively, maintain the existing capacity benchmark methodology; (5) add a GHG-free benchmark of $6.14/MWh to the PCIA benchmark for 2019, subject to reconsideration if market conditions change; and (6) adopt the Proposed Decision's formulation of a cap and collar.

II. A CCA THAT SURVIVES THE COST SHIFT WOULD BE UNABLE TO DEPLOY PROCUREMENT STRATEGIES TO SUPPORT ACCELERATION OF THE STATE'S DECARBONIZATION AND ECONOMIC JUSTICE GOALS.

The APD would affect all CCAs differently, depending upon their departure vintage, service territory and procurement strategy, but it offers only "bad news" for the majority of CCAs. Relative to the 2019 ERRA values, the departing load burden on PG&E's system would increase by $177 million or on average roughly 0.47 ¢/kWh (17 percent).[3] Similarly, the departing load burden on SCE's system would increase by $180 million or, on average, roughly 0.57 ¢/kWh (38 percent).[4] Bundled customers of both utilities, however, would see cost reductions commensurate with the departing load increases. The cost shift would make a launching CCA uneconomic from the outset and strand costs in the portfolios of existing CCAs. Even if a CCA could survive this cost shift, the APD would drive short-term procurement and other practices that undermine the state's decarbonization and economic justice policy goals.

The problem created by the APD is made obvious in comparing the relative positions of bundled utility and CCA departing load customers under the APD. The APD will produce utility bundled customer rates *below* the rates a CCA could offer its customers if the CCA procured 100 percent of its portfolio at the benchmarks set by the APD and mirrored the utility's mix of brown, RPS and GHG-free energy.[5] Most notably, both Residential and Small Light & Power (L&P) would be "under water" by 0.3¢/kWh and nearly 1¢/kWh respectively. Taking a more reasonable view of capacity costs ($58.276 kW-year) and adding a GHG-free premium (0.614¢/kWh) for 50 percent of the portfolio, the disadvantage of CCA Residential customers relative to bundled customers grows to 1¢/kWh, and the Small L&P gap grows to 1.71¢/kWh. The results of the latter scenario are shown below in Figure 1 (Residential) and Figure 2 (Small L&P).

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3 Based on a comparison of PG&E's projected system-average PCIA rates and projected allocation of charges to departing load customers vs. the proposed 2019 ERRA, per the workpapers supporting PG&E's APD rate tables submitted on August 31, 2018.

4 Based on a comparison of SCE's projected system-average PCIA Indifference Rates and projected allocation of charges to departing load customers vs. the proposed 2019 ERRA, per the workpapers supporting SCE's APD rate tables submitted on August 31, 2018.

5 This illustration also accounts for CAISO costs at 5 percent and losses at 6 percent.

Figure 1

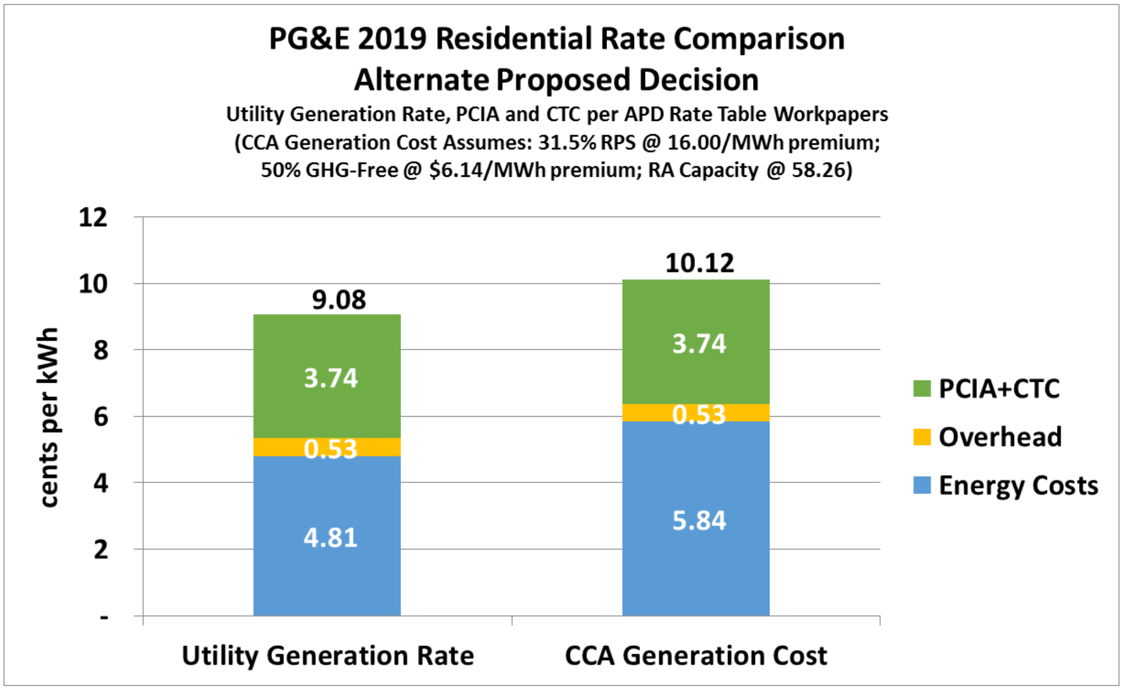
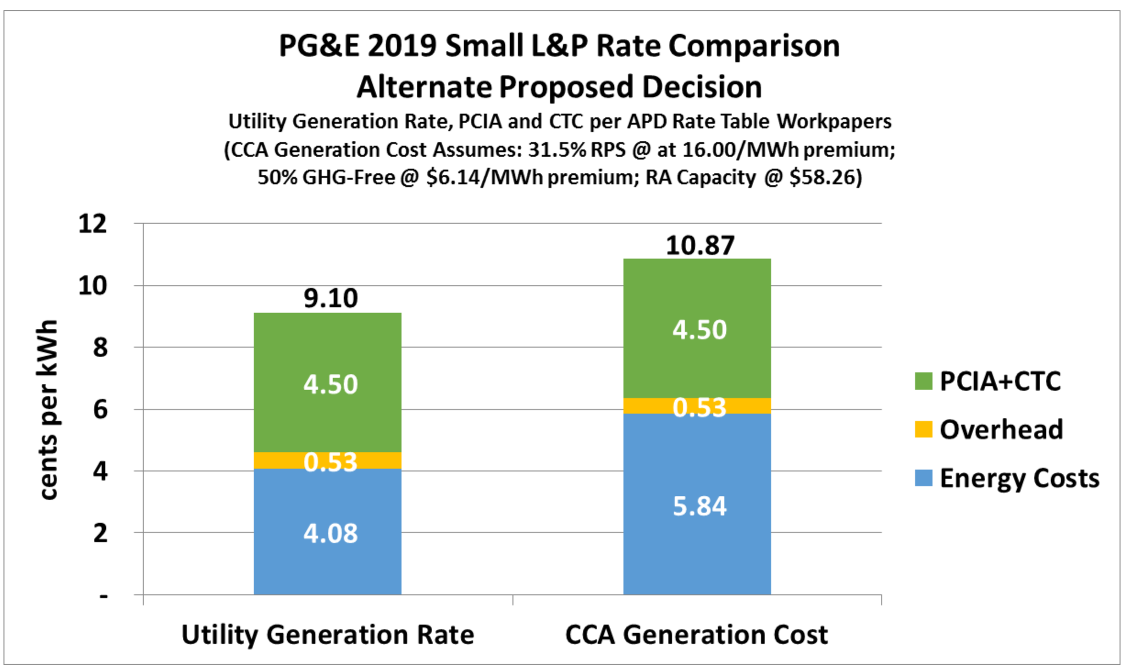


Figure 2



While the schedules showing the greatest disadvantage on the SCE system differ from PG&E, CCA customers are "under water" by roughly 0.9¢/kWh on a system average basis relative to SCE customers.

Under these conditions, a newly launching CCA could not duplicate the energy costs implied by the generation rate and PCIA even with minimal RPS compliance. Simply put, the benchmarks used to value the utilities' portfolios do not fairly value the cost of replacement. As the Commission has represented to the Legislature, the utility could not replace its RPS portfolio at short-term market prices;[6] neither can a CCA build a portfolio solely at short-term prices.

While a new CCA might experience a failure to launch, an existing CCA may be even further harmed as resources in their own portfolios are stranded. If, for example, the existing CCA purchased an RPS resource for $100/MWh in 2011, the APD's proposed RPS benchmark of roughly $16/MWh would strand $84/MWh in RPS costs. Unlike utility customers, however, CCA customers would not be able to recover any portion of their stranded costs from bundled customers. This effect, combined with CCA customers being made responsible for avoidable utility costs, financially penalizes CCAs that entered into long-term contracts for new renewable resources.

Even if a CCA could economically serve their customers under these unequal conditions, the APD's benchmark would drive a change in the CCA's business model that undermines the state's policy goals. Rather than engaging in new RPS project development with a long-term power purchase agreement, a CCA would be driven to procure low-cost attributes to reduce risk, maximizing PCC 2 RECs to comply with the RPS. Likewise, rather than making a financial commitment to long-term capacity, the CCA aims for minimum compliance levels with short-term RA transactions to manage its risk. Finally, and most critically, it would be impossible for the CCA to fund the types of services they were intended to promote – *e.g.,* innovative electric vehicle programs, procurement of local premium resources or programs for low-income residents and disadvantaged communities -- while staying competitive with utility rates.

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6 *See infra* Section VI.

The APD results in untenable conditions that threaten the vision of CCAs as a tool to achieve the state's decarbonization and environmental justice goals, while providing local communities services that best match their needs.

III. THE APD IGNORES THE LAW AND POLICY HISTORY BY INCLUDING LEGACY UOG COSTS IN THE SCOPE OF PCIA-ELIGIBLE COSTS.

The law requires exclusion of Legacy UOG costs from the scope of PCIA-eligible costs recovered from CCA customers. The APD concludes, to the contrary, that Legacy UOG costs must be included to "prevent any shifting of recoverable costs between customers,"[7] To reach this conclusion, the APD ignores the express terms of AB 117and substitutes its own baseless interpretation of the Legislature's "cost shift" directives. The APD also ignores the history and policy considerations surrounding the Legacy UOG exclusion. Finally, by continuing to include Legacy UOG, the APD places responsibility for new capital investment costs in these facilities on CCA customers *long after their departure.* It is the Commission's province to apply, not rewrite, the law, and the final decision must exclude Legacy UOG from CCA customer cost responsibility.

A. California Law Does Not Include Legacy UOG in CCA Cost Responsibility.

1. AB 117 Specifies Four Categories of Costs, and Legacy UOG Is Not Included in These Categories.

The AB 117 Legislative Counsel Digest requires the Commission to adopt a cost-recovery mechanism for CCA departing load "to prevent a shifting of costs to an electrical corporation's bundled customers.[8] The operative sections further illuminate this intent:

> After certification of receipt of the implementation plan and any additional information requested, the commission shall then provide the community choice aggregator with its findings regarding any cost recovery that must be paid by customers of the community choice aggregator ***to prevent a shifting of costs as provided for in subdivisions (d), (e), and (f)***.[9]

7 APD at 48.

8 AB 117, Legislative Counsel Digest, §(1).

9 Cal. Pub. Util. Code § 366.2(c)(7) (emphasis added).

Notably, the Legislature did not give the Commission free reign in developing a cost recovery mechanism for CCA departing load. Instead, it limited cost recovery to the categories described in subdivisions (d), (e), and (f):

- California Department of Water Resources (CDWR) bond charges[10];
- CDWR "estimated net unavoidable electricity purchase contract costs" [11];
- "[U]nrecovered past undercollections for electricity purchases…." [12];
- A CCA customer's "share of the electrical corporation's estimated net unavoidable ***electricity purchase contract costs*** attributable to the customer." [13]

In glaring absence, the statute has no references to UOG, despite the Legislature's express acknowledgement of UOG in other circumstances.[14] And, importantly, because Legacy UOG was built and put into ratebase before 2002 and addressed by the Legislature in a 2001 extraordinary session,[15] the Legislature knew in enacting AB 117 that these costs existed.

The Legislature made no further references to procurement cost shifts until 2015. SB 350 has one reference to cost shifting, which targeted "additional procurement",[16] *i.e.*, future procurement, through the utility's integrated resource plan. Once again, no mention was made of Legacy UOG.

Beyond these "cost shift" provisions, the Legislature provided more generic language in SB 350:

> 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. 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.[17]

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10 Cal. Pub. Util. Code § 366.2(e)(1).
11 Cal. Pub. Util. Code § 366.2(e)(2).
12 Cal. Pub. Util. Code § 366.2(f)(1).
13 Cal. Pub. Util. Code § 366.2(f)(2).
14 *See, e.g.,* Cal. Pub. Util. Code § 330(s) ("It is proper to allow electrical corporations an opportunity to continue to recover, over a reasonable transition period, those costs and categories of costs for generation-related assets and obligation…."); *see also* Assembly Bill 1 (Stats. 2001, 1st Ex. Session 2001, ch. 4) (hereafter, AB IX); Cal. Pub. Util. Code §367 (distinguishing between the utilities' "generation-related assets" and "power purchase contracts".)
15 Assembly Bill X1-6, 2001-2002 1st Ex. Session, ch. 2 (AB X1-6); Cal. Pub. Util. Code § 377.
16 Cal. Pub. Util. Code § 454.52(c).
17 Cal. Pub. Util. Code § 366.3.

The phrase “cost increase” lacks the specificity present in AB 117 and indicates no intent to repeal AB 117.

Nothing in the key statutory frameworks at issue in this proceeding provides authority for allocation of Legacy UOG to CCA departing load customers.

B. Canons of Statutory Interpretation Compel the Conclusion that the Legislature Intended to Exclude Legacy UOG from CCA Customer Cost Responsibility.

The APD concludes erroneously that excluding Legacy UOG from CCA customer cost responsibility would violate “’the cardinal rule of statutory construction, that a statute must be read and considered as a whole, in order that the true legislative intention may be determined.’”[18] CalCCA agrees that rules of statutory construction are critical in the analysis of CCA customer cost responsibility.

There is only one way to understand AB 117 given the Legislature’s clear language: AB 117 intended to create cost responsibility only for those cost categories identified in §366.2(d), (e) and (f). As the PD correctly noted,[19] *expressio unius est exclusio alterius* – “the expression of one thing implies the exclusion of others”[20] – is a well-settled canon of statutory interpretation in California law. In AB 117, the Legislature specified the costs that were to be borne by departing load customers. Under *expressio unius*, that list must necessarily be interpreted to be exclusive unless a contrary legislative intent is expressed in the statute or elsewhere.[21] Here, as discussed above, there is no contrary legislative intent expressed elsewhere that would preclude the application of *expressio unius* in this case. On the contrary, the Legislature has made its position perfectly clear. Legacy UOG costs may not be recovered from CCA departing load.

This conclusion is supported by the application of yet another canon of statutory interpretation. "When two statutes touch upon a common subject," we must construe them "in reference to each other, so as to harmonize the two in such a way that no part of either becomes

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18 APD at 47 (citations omitted).

19 PD at 51.

20 *Dyna-Med, Inc. v. Fair Employment & Housing Com.* (1987) 43 Cal.3d 1379; *Center for Community Action & Environmental Justice v. City of Moreno Valley* (2018) 2018 Cal. App. LEXIS 757.

21 *Fields v. Eu* (1976) 18 Cal.3d 322, 332; *CPF Agency Corp. v. Sevel’s 24 Hour Towing Service* (2005) 132 Cal.App.4th 1034.

surplusage."[22] We must presume that the Legislature intended "every word, phrase and provision ... in a statute ... to have meaning and to perform a useful function."[23] Contrary to the principles expressed in the APD, to interpret the general language of SB 350 as covering any possible cost – regardless of category or time of incurrence -- renders the enumeration of specific cost categories in AB 117 and, within SB 350, in §454.52(c) "surplusage."

The two statutes can be harmonized only by concluding that the general references to "cost shift" or "cost increase" are just a high level expression of a principle that can be applied in many ways, and the more specific language of §366.2 and §454.52(c) give practical meaning to the general concept. Concluding that SB 350 broadened the scope of includable costs would be to rewrite AB 117 and §454.52(c). California courts have refused such a result and have stated "[T]he requirement that courts harmonize potentially inconsistent statutes when possible is not a license to redraft the statutes to strike a compromise that the legislature did not reach."[24] There is nothing in the legislative history of SB 350 to suggest or support the contention that the legislature ever intended to repeal AB117, alter the includable costs for departing load or amend AB 117 and §454.52(c) to include Legacy UOG. However, the APD would in effect allow SB 350 to repeal the legislature's express language in AB 117 and presuppose the legislature's intention. Such a result is contrary to the cannons of statutory interpretation and in violation of court holdings that an implied repeal of a statute is only appropriate when there is no possible way to harmonize the statutes. [25]

During the course of the oral arguments, Mr. Freedman of TURN introduced another canon of statutory interpretation used when two statutes cannot be harmonized. Mr. Freedman argued that a "later enacted statute should be given more weight, and it should be harmonized with the earlier statute."[26] He seemed to suggest that the specific cost responsibility terms of AB

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[22] *DeVita v. County of Napa* (1995) 9 Cal.4th 763, 778-779; *See Dyna-Med, Inc. v. Fair Employment & Housing Com.*, supra, 43 Cal.3d at 1387;

[23] *City and County of San Francisco v. Farrell* (1982) 32 Cal.3d 47, 54; *California State Employees' Assn. v. State Personnel Bd.* (1986) 178 Cal.App.3d 372, 378.

[24] *Lopez v. Sony Electronics* (2018) 5 Cal.5th 627.

[25] "Absent an express declaration of legislative intent, courts will find an implied repeal 'only when there is no rational basis for harmonizing two potentially conflicting statutes and the statutes are irreconcilable, clearly repugnant, and so inconsistent that the two cannot have concurrent operation.' " *State Dept. of Public Health v. Superior Court* (2015) 60 Cal.4th 940,955,citing *Pacific Palisades Bowl Mobile Estates, LLC v City of Los Angeles* (2012) 55 Cal.4th 783, 805.)

[26] 6 Tr. 1215:23-25 (Freedman/TURN); TURN Comments on PD at 6.

117 should be ignored in favor of the later, general statement regarding cost shifts and increases in SB 350. As an initial matter, this canon applies only when two statutes can be harmonized. In this case, they are easily harmonized by assuming that SB 350 was intended to reiterate in a more generalized fashion rules applicable to CCAs, not repeal AB 117 and §454.52(c), as discussed above. And, even if they could not be harmonized, California case law does not support Mr. Freedman's conclusion. The California Supreme Court has as recently as July 2018 reiterated the rule that specific statutory provisions take precedence over more general provisions and, importantly, trumps the rule that later-enacted statutes have precedence.[27]

C. The History Surrounding AB 117 Explains and Supports Exclusion of Legacy UOG from CCA Cost Responsibility.

The APD goes beyond legal interpretation and concludes "[w]e cannot find a principled justification to exclude those costs for CCA customers because they are now above-market."[28] To exclude these costs, the APD explains, "amounts to an invitation to shift costs to bundled customers that were incurred to serve CCA customers who later departed."[29] The APD overlooks important history and policy underlying the statute and fails to recognize utility costs are not always appropriately allocated to customers; utility shareholders must also be accountable for costs, particularly those costs that are avoidable and due to portfolio mismanagement.

The same assets now characterized as "Legacy" generation were originally the subject of the Competition Transition Charge.[30] Recovery of stranded costs of these assets on a nonbypassable basis was permitted to the extent the assets "may become uneconomic as a result

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27 As recently as July 5, 2018 the California Supreme Court in *Lopez v. Sony Electronics* (2018) 5 Cal.5th 627 reiterated the concept that a specific statute will take precedence over a later enacted, more generalized statute in conducting their analysis of two statutes enacted sixty years apart. The Supreme Court cited *State Department of Public Health v. Superior Court* (2015) 60 Cal. 4th 940 which in turn cited *People v. Gilbert* (1969) 1 Cal.3d 475, 479 wherein the court stated "it is the general rule that where the general statute standing alone would include the same subject matter as the special act, and thus conflict with it, the special act will be considered as an exception to the general statute whether it was passed before or after such general enactment."

28 APD at 48.

29 *Id.*

30 Cal. Pub. Util. Code § 367.

of a competitive generation market…."[31] The Legislature provided that collection of the Legacy UOG costs "shall not extend beyond December 31, 2001…."[32]

Now, once again, *these same assets* are "uneconomic," and the utilities continue to earn a return and to recover "uneconomic" costs through the life of the assets under the PCIA. The Legislature and the Commission, in 2002 when AB 117 was enacted, could not have begun to imagine that the Legacy UOG would continue to generate stranded costs more than 20 years later. Rather, they expected that bundled customers would benefit greatly by retaining full rights and obligations to those resources, and departing customers were forsaking that benefit.

This view was reinforced in 2002, when long-term contracts newly signed by the Department of Water Resources (CDWR) loomed as a large obligation for the next decade. Direct Access customers were obligated, in a rough exchange for a later suspension of DA service,[33] to pay the costs of the CDWR contracts. CLECA and other parties argued that if DA customers took on the above-market costs of CDWR contracts, the costs should be offset by the benefits of *lower cost* Legacy UOG.[34] The Commission ultimately adopted CLECA's recommendation in D.02-11-022, imposing the above-market costs of CDWR contracts on DA customers, counterbalanced by including lower cost Legacy UOG and an extension of the implementation date for the statutorily mandated suspension of DA.

While DA customers, whose obligations were not defined by AB 117 and for whom Legacy UOG were not specifically excluded, may have benefitted from this netting in the early years, CCAs have not similarly benefitted. Through 2010, Legacy UOG resources provided an "offset" to the other PCIA costs. Thereafter, however, Legacy UOG has been consistently uneconomic, contributing $545 million in uneconomic costs to PG&E's 2018 PCIA. [35]

For all of these reasons, history and policy support the legal conclusion that Legacy UOG should not be included in the CCA PCIA.

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31 *Id.*
32 *Id.*
33 D.02-11-22.
34 *Id*. at 23.
35 Exh. CalCCA-3 at 7-13:13-16 and Exhibit 7-A.

D. Leaving Legacy UOG in the PCIA Violates Indifference Principles as Capital Investment Continues.

The Commission has drawn a clear line for departing load cost responsibility: "stranded costs related to resource and contractual commitments made by the IOU *up until the time* of the customer's departure."[36] The APD violates this principle by requiring departed customers to continue to pay the costs of new capital investment in, and uneconomic operating costs of, Legacy UOG resources long after a CCA customer departs.

As detailed in CalCCA's testimony and briefs, under the current and proposed values for the market price benchmark, there are uneconomic, short-term operating costs from Legacy UOG nuclear and fossil facilities.[37] This fact cannot be justified by the assertion that these are reliability resources. Neither the nuclear nor Legacy fossil facilities provide local or necessary system reliability benefits and are operated solely for the benefit of bundled customers.[38] In fact, the Commission recently determined that "[t]he retirement of Diablo Canyon will not cause adverse impacts on local or system reliability,"[39] while Pebbly Beach is located on an island with no connection to the grid and Palo Verde is in Arizona.[40]

The short-term operating costs for these facilities (fuel, fixed and variable O&M, A&G, property and payroll taxes, etc.) are all incurred on an annual basis, as are new capital additions.[41] Capital additions for Legacy UOG are hundreds of millions per year.[42] Combined, the billions in costs for recent capital additions and short-run operating costs (all incurred after the departure of most existing CCAs) comprise a significant amount, if not the entirety of the uneconomic costs calculated for the Legacy UOG facilities.[43]

As these costs were incurred after the departing load customers left, it is neither equitable nor lawful to attribute them to CCA departing load customers. Doing so allows bundled customers to benefit by shifting to CCAs costs that were not caused by CCAs. Bundled customers are not indifferent, they are better off.

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36 D.08-09-012 at 59 (emphasis added).
37 CalCCA Testimony at 2B-17; CalCCA Rebuttal Testimony at 2B-6 to 2B-8
38 See Joint Utilities Submittal on UOG Capacity, distributed by email on August 7, 2018.
39 D.18-01-022, Finding of Fact 2.
40 CalCCA Testimony, pages 2B-17 and 18.
41 CalCCA Testimony, page 2B-17
42 *See, e,g*, D.14-08-032, pages 358 and 413.
43 CalCCA Rebuttal Testimony, page 2B-6.D.

E. The Commission Has Tools to Mitigate Impacts Resulting from Conforming the PCIA to Statutory Requirements for Legacy UOG Cost Recovery.

The Joint Utilities have had no reasonable expectation of continuing to recover stranded costs and earn a return on Legacy UOG. AB 1890 contemplated recovery of the uneconomic costs of these resources "over a reasonable transition period" to the extent the costs were "necessary to maintain those facilities through December 31, 2001."[44] The direction was modified in 2001 by the Legislature, precluding "disposal" of these assets in the wake of the energy crisis.[45] Even at that time, however, the Legislature did not authorize additional stranded cost recovery, it sunset the disposal prohibition on January 1, 2006,[46] and it expressed its legislative intent that "generation of electricity should be open to competition."[47] Allowing stranded cost recovery for Legacy UOG resources (for which ratepayers have already paid billions of dollars in stranded costs[48]) well into 2018 and beyond, while the utilities continue to earn a return for shareholders, is unjustifiable.

CalCCA acknowledges the Commission's concern regarding the cost burden for bundled customers. Solutions are available, however, to address this burden. CalCCA proposed securitization of the UOG, which would replace the utilities' return with interest on lower cost secured bonds, significantly benefitting all customers.[49] CalCCA calculated that in the first year, assuming a 20-year bond term, this would reduce portfolio costs by $496 million for PG&E and $131 million for SCE. [50] Over the 20-year term of a securitization bond issuance, the benefits have a net present value of $1.3 billion for PG&E and $589 million for SCE. [51] Similarly, while outside the scope of this proceeding, the Commission could reduce the utility's rate of return for certain UOG assets as it has in the past, recognizing the security provided by transition cost recovery. [52]

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44 Cal. Pub. Util. Code § 330(s).
45 Assembly Bill X1-6, 2001-2001 1st Ex. Session, Ch. 2; Cal. Pub. Util. Code § 377.
46 AB X1-6.
47 Assembly Floor Analysis, January 18, 2001 at 3.
48 *See, e.g.,* D.95-12-063.
49 CalCCA Opening Brief at 115 *et. seq*.
50 Id. at 116; Exh. CalCCA-1 at 3-7:7-9.
51 Exh. CalCCA-1 at 3-7:7-9. Exhibit 3-A.
52 *See, e.g.,* D.95-12-063 at 64.

IV. THE APD RELIEVES THE UTILITIES OF IMPORTANT PORTFOLIO MANAGEMENT OBLIGATIONS WITHOUT DEMONSTRATING THAT SUCH RELIEF IS WARRANTED.

The APD removes the long-standing 10-year limitation on cost recovery from departing load customers for post-2002 non-RPS UOG resources. Adhering to its one-dimensional view of the issue, the APD concludes that removal is required to "equitably distribute stranded costs."[53] The APD further concludes that there is "no justification" to *continue* the limitation, ignoring prior Commission decisions[54] that instead require a utility to justify *removing* the limit. The APD not only contradicts prior decisions, it removes important boundaries aimed to place responsibility on the utilities to reasonably forecast and manage their portfolios. The Commission should thus reject the APD's conclusion and retain the 10-year limitation on cost recovery for post-2002 non-RPS resources.

The Joint Utilities were fully aware of the 10-year limitation *before* they made their respective post-2002 resource investments. The Commission also made clear its expectation that the utilities would manage the risk associated with the 10-year limit – presumably on behalf of both bundled ratepayers and shareholders – through prudent planning.[55] The same expectation was stated when the Commission implemented AB 117 in 2004, observing the need for "reasonable assumptions about future electricity demand" as a foundational requirement for recovery of the costs through the "Cost Responsibility Surcharge."[56] Well aware of these expectations, the utilities moved forward with new UOG resources.

The record in this proceeding reveals a clear failure to take seriously the risk of departing CCA load – a factor that should have significantly affected their portfolio management practices. CCA departing load was foreseeable as early as 2009,[57] yet the Joint Utilities refused to forecast these departures until a CCA provided a binding notice of intent.[58] (In fact, PG&E continued to procure "on behalf of" Marin Clean Energy even *after* customer departures.)[59] Even today, the

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53 APD at 52.
54 D.03-12-059 at 35; D.04-12-048 at 63; *See generally* D.08-09-012 at 49-52.
55 D.08-09-012 at 54-55.
56 D.04-12-046 at 29.
57 CalCCA Opening Brief at 97.
58 *Id.*; 4 Tr. 809:20-810:3 (Cushnie).
59 *See* Exh. CalCCA-123, PG&E 2010 Contract Execution Dates From Attachment 10 ALJ Requested Data Matrix; *see also* 4 Tr. 820:17-823:20 (Lawlor).

utilities maintain that they cannot reflect CCA departures in their forecasts without near-certainty that a CCA is launching.[60] The Joint Utilities' stubborn failure to forecast departing load has created avoidable costs and cannot be justified.

While the Commission's expectations were clear, the 10-year limit was not absolute. The Commission left room for the utilities "to justify in their applications, on a case-by-case basis" extending the cost recovery period.[61] The APD does not conclude, however, that the Joint Utilities have provided such justification. Indeed, the Joint Utilities have made no request to lift the limitation over the past 14 years, nor have they made any showing to demonstrate that they have taken every reasonable action to adjust their portfolios to address the limitation. In fact, SCE discontinued inclusion of Mountainview, the first resource to which the limitation was applied, in the PCIA at the conclusion of the 10-year limitation as mandated.[62] It did so without any request to extend PCIA cost recovery for this resource.

For all of these reasons, the Commission should retain the 10-year limitation and seek other solutions to reduce the bundled costs for these resources.

V. ANY TRUE UP SHOULD BE LIMITED TO A TRUE-UP OF FORECAST AND ACTUAL REVENUES.

CalCCA observed in its PD comments that an annual PCIA true-up would undermine the goals of stability, certainty and predictability advanced by the Scoping Memo.[63] Moreover, a true-up, while perhaps leading to greater accuracy in valuing brown power in the portfolio (if the value of hedging price risk in long-term contracts is ignored), cannot achieve the same accuracy in valuing the long-term capacity and RPS resources.[64] Finally, a true-up of RA or RPS sales revenues against the portfolio valuation benchmark presents an opportunity for utility

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60 4 Tr. 811:17-24 (Lawlor/PG&E).

61 D.04-12-048 at 63.

62 SCE stated in its 2017 Forecast ERRA, filed May 2, 2016: "Pursuant to D.03-07-032 and D.04-12-048, the ten-year limit on stranded cost recovery for SCE's UOG Mountainview Generating Station has ended. As such, its costs, energy, and capacity have been removed from the Total Portfolio calculation." ERRA Testimony, at 99. http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/8D370FAB84E5CACB88257FA8007B7CEE/$FILE/A1605001-SCE-Various-%20SCE%201%20Testimony%20.pdf

63 CalCCA PD Comments at 5.

64 *Id*. at 6.

manipulation; the lower the prices at which utilities sell excess resources, the higher the PCIA and the greater the burden on the utilities' competitors.[65]

In particular, the APD's support for a zero or *de minimis* value for unsold capacity and RPS resources provides a perverse incentive for the utilities to withhold these products from the market and pass the stranded costs from this "excess" capacity and RPS to CCA customers. This is particularly problematic for capacity. For example, a utility could withhold capacity from the market to act as a buffer to noncompliance penalties, or it could offer capacity to the market at an unreasonably high price under the guise of a price floor not supported by the market. Under the APD, failing to sell the capacity for either reason would subject the capacity to a zero or *de minimis* valuation. Consequently, bundled customers would enjoy the full benefit of these resources to the extent they are actually or potentially needed to serve bundled load in the long run, while CCA customers would be forced to pay for the inflated "above-market costs" of that "excess" capacity and also pay for capacity from another resource procured by their CCA to meet its compliance requirements. Not only does the APD unlawfully permit this cost shift from bundled load customers to departing load customers, this policy is unreasonable and only serves to amplify the utilities' market dominance and ability to shift costs to CCA customers.

In light of these concerns, CalCCA proposes a limited true-up, pending implementation of Phase 2, and clarification of the mechanics of the true-up in the ERRA proceedings.[66] CalCCA proposes a true-up of forecast to actual, realized values: (1) total generation quantities and costs; (2) energy purchase and sales revenues; (3) reasonably forecast RA purchase and sales revenues; and (4) reasonably forecast RPS purchase and sales revenues. The forecast portfolio value, or benchmarked market value, would not be subject to true up. As CalCCA discussed more extensively in its PD comments, truing up the portfolio valuation does not increase accuracy and would introduce greater, unnecessary instability for CCAs.

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[65] *Id*. at 13.
[66] *Id*. at 11.

VI. THE PROPOSED CAPACITY BENCHMARK MUST MORE REASONABLY REFLECT THE VALUE OF CAPACITY IN THE JOINT UTILITIES' PORTFOLIOS.

As CalCCA demonstrated in its PD comments, the PD and APD scrape the bottom of the barrel in choosing a benchmark to represent the value of capacity in the Joint Utilities' portfolios.

- The proposed value is nearly the lowest value considered in the record of this proceeding,[67] ignores the long-term reliability and price hedging value inherent in the utilities' portfolios and is belied by the operating costs (and replacement costs) of the Joint Utilities' own resources.[68]

- The benchmark is drawn from the sale of resources representing, at most, 10 percent of the capacity used for RA compliance purposes but is used to value 100 percent of the long-term resources in the utilities' portfolios.[69] This approach is directly contrary to the Commission's conclusions in the May 2017 Padilla Report to the Legislature on RPS value, which rejected the use of short-term values to value a broad portfolio of resources.[70]

- Even the Joint Utilities admit that there is more value to RA capacity than the value that can be realized through short-term sales,[71] and both the utilities and the Commission routinely rely on vaguely-defined and unquantified "portfolio value" contributions beyond RA Capacity value to justify the addition of new advanced or distributed resources.[72]

Reliance on the small sample of short-term sales presents a particular problem, ignoring available cost data for providing roughly 30 percent or more of the system RA needs from UOG facilities.[73] The short-run costs (not including sunk costs) the utilities incur to provide RA from existing UOG resources are reviewed in the GRC and ERRA proceedings. In fact, the existing PCIA proxy for RA ($58.27/kW-year) is based on the CEC's estimate of the minimum short-run cost of providing RA from a utility fossil facility. If the Commission prefers using actual short-term costs rather than relying on the CEC forecast, it should include the utilities' short-term UOG

67 *Id*. at 10.
68 *Id*. at 11.
69 2017 RA Report
70 *Id*. at 10.
71 *Id*.
72 A recent example is the approval of SCE's procurement of 125 MW of contracted distributed energy resources which were "…justified by the magnitude of their collective expected contribution to local system reliability, existing Commission programs, and larger state policy goals, such as grid modernization, DER penetration, and greenhouse gas reductions." D.18-07-023 at 14.
73 *Id*.

RA costs. As shown in CalCCA's testimony and briefs, this value is roughly $85/kW-year for PG&E's fossil plants and Diablo Canyon.[74] These costs represent a much greater share of the overall RA market than the values from the Commission's RA report, and are available, verifiable and just as relevant to current market costs. They are also less volatile than short-term market prices.

The APD also fails to specify which value from the RA Report it proposes to use. In the CAISO energy and ancillary services[75] markets, the market clearing price used to set the value of the energy portfolio is determined by the *highest* accepted bid in a single hour, and then averaged across all hours. Similarly, the appropriate RA price metric is the *highest* RA transaction price for each month. This price represents the market equilibrium point at which a consumer is willing to pay the highest price given how low a price a supplier is willing to provide that quantity of the resource. In a full auction market, all transactions would clear at this price, which is why the CAISO reports a single market clearing price for all transactions in a single hour. That should also be the case for the RA market price, except the time unit is a month. In other words, the value representing 85 percent (of the 10 percent) of the MW for which contract prices are available should be the minimum value drawn from the RA Report for any purpose.

Finding an "accurate" value for capacity is admittedly challenging, due to wide variation in how capacity is procured for RA compliance (*i.e.*, purchases and sales, UOG capacity held in the PCIA portfolio, UOG capacity allocated through the Cost Allocation Mechanism, and the California Independent System Operator's (CAISO's) Capacity Procurement Mechanism (CPM)). Recognizing the challenge, CalCCA proposed in its PD comments compromise benchmarks for system, local and flexible capacity; while these benchmarks still fail to reflect long-term value, they at least provide more reasonable short-term values.[76] The benchmarks rely on the Energy Division's annual RA Report, as the APD proposes, but only in proportion to the extent of the report's actual market representation. The remaining system capacity is valued using the existing short-term CEC-developed benchmark, and the remaining local capacity is

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74 CalCCA Opening Brief at 58.

75 The ancillary services market values have been excluded from the ERRA market price benchmark to date, and neither the PD or APD addresses how to include this value. Further the market value of residual unit commitment also is excluded because it is covered instead through a side payment that is included in the portfolio costs, but excluded from market price benchmark.

76 CalCCA PD Comments at 13-14.

valued at the prices paid under the CAISO's CPM. Since there are no reliable data sets for flexible capacity, CalCCA proposes to rely on the existing CEC-developed benchmark for that purpose. The Commission should adopt CalCCA's compromise approach until a reasonable method for market valuation of long-term resources has been implemented following Phase 2.

If the Commission does not adopt CalCCA's compromise, it should freeze the existing benchmark, continuing to rely on the CEC's short-term capacity cost calculation for all capacity. While this proposal fails to bring the benchmark any closer to the needed long-term valuation, it lies closer to the middle of values discussed in this proceeding and does no harm relative to the existing benchmark.

VII. THE APD IGNORES RECORD EVIDENCE OF GHG-FREE VALUE FOR HYDRO AND NUCLEAR RESOURCES.

CalCCA proposed to augment the existing portfolio valuation measure to include an explicit premium above brown power prices for GHG-free resources.[77] As CalCCA witness Kinosian testified: "GHG-free generation carries a premium in today's market, although no reliable published market index values for this generation exist." [78] While the APD notes CalCCA's position,[79] as well as the similar positions of Shell[80] and UCAN,[81] it fails to draw *any* conclusion – for or against -- regarding the proposal. The APD thus contravenes §1705, which requires that the Commission's decisions "shall contain, separately stated, findings of fact and conclusions of law by the commission *on all issues material to the order or decision*."[82] It further fails to adequately value the resources in the Joint Utilities' portfolios and thus causes a cost shift from bundled to departing load customers.

CalCCA discussed extensively in testimony and in briefs the growing value of non-RPS GHG-free resources, highlighting:

- The importance of these resources in marketing and public relations strategies evidenced by the Joint Utilities' websites and SCE's "Clean Power and Electrification Pathway" initiative;[83]

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77 Cal CCA Opening Brief at 63.
78 *Id.* at 2B-10:8-9.
79 APD at 17.
80 *Id.* at 60.
81 *Id.* at 62.
82 Cal. Pub. Util. Code § 1705 (emphasis added).
83 CalCCA Opening Brief at 63-64.

- The value of these resources as reflected in the Power Content Label required for each LSE;[84]
- PG&E's suggestion in the Diablo Canyon retirement proceeding that the output of the resource should be replaced by GHG-free resources, up to a cost cap reflecting the same premium applied to RPS resources. [85]
- Evidence of solicitations in which PG&E participated expressly seeking "carbon free" products. [86]
- The Joint Utilities' acknowledgement that market participants have placed value on GHG-free energy. [87]

In addition, Senate Bill 100 (SB100), which was passed by the Legislature on August 29, 2018, would establish "the policy of the state that eligible renewable energy resources and zero-carbon resources supply 100 percent of all retail sales of electricity to California end-use customers…by December 31, 2045."[88] It would only raise the state's RPS requirements, however, to 60 percent by 2030.[89] SB 100 thus raises the value of zero-carbon resources that, in combination with RPS-eligible resources, would have California achieve its 100 percent goal. It further directs the Commission to "incorporate this policy into all relevant planning."[90] The utilities' current ownership of almost all of California's existing GHG-free resources available to serve California's CPUC-jurisdictional load requirements gives them a significant "avoided cost" advantage in meeting SB100 and the Commission's Integrated Resource Planning GHG reduction requirements.

Identifying a reasonably representative value for GHG-free attributes, like capacity value, presents a challenge. CalCCA proposed the integration of a GHG-free premium equal to the RPS premium, based on PG&E's Diablo Canyon testimony. [91] The Joint Utilities' opposed CalCCA's proposal, but cited anecdotal evidence of GHG-free value, ranging from $2/MWh to their own calculation of potential value of $6.14/MWh.[92] The APD ignores this debate, and by

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84 *Id.*at 64.
85 *Id.*at 64-65.
86 *Id.*at 61.
87 *Id.*at 62.
88 Sen. Bill 100 (2017-2018 Reg. Sess.)
89 *Id.*
90 *Id.*
91 CalCCA Opening Brief at 66-67.
92 *Id.* at 65-66. These figures are significantly below the GHG prices recently adopted by the Commission in its Integrated Resource Planning process (D.18-02-018), where the Commission directed

doing so effectively places the same value on GHG-free energy as it places on fossil-fired generation. This approach is out of step with state policies favoring reductions in GHG emissions, and adoption of a GHG-free attribute value is necessary to prevent a cost shift from bundled to departing load customers.

The need for a GHG-free premium is significantly reduced when the Joint Utilities' non-RPS GHG-free resources are excluded or limited, as proposed by the PD.[93] Under the APD, however, it is critical to ensure that all portfolio values are captured. Lacking a particular GHG-free index, the APD should thus be modified to adopt a moderate GHG-free premium of $6.14/MWh for 2019, as calculated by the Joint Utilities, subject to reconsideration as the market evolves.

VIII. A 25 PERCENT RATE OF CHANGE "COLLAR" COMMENCING IN 2020 WILL NOT ADEQUATELY MITIGATE VOLATILITY.

While CalCCA did not originally propose a cap or collar in testimony, the magnitude of the APD's increases compels the effective use of these tools to mitigate volatility. The APD's proposed price cap and collar, however, are "too little and too late." The percentage collar is too wide to be an effective check on volatility, and the APD proposes not to deploy the tool until the 2020 ERRA.

CalCCA supports the PD's approach, including a cap of 2.2¢/kWh for 2019 and a .5¢ collar thereafter until Phase 2 has been fully implemented. Based on SCE's illustrative rates, the cap will have no effect on SCE's PCIA rates, the highest of which is forecast to be 1.980¢/kWh. While the cap will affect PG&E's PCIA rates, the capping is reasonable in light of the significant disparity of PCIA rates between PG&E and SCE; PG&E's PCIA rates are roughly twice the level shown by SCE. The PD's approach is also supported by the history of PCIA rate changes for PG&E departing load customers. For example, under the APD, PG&E's System Average PCIA rates will have risen approximately *226 percent,* since 2015.

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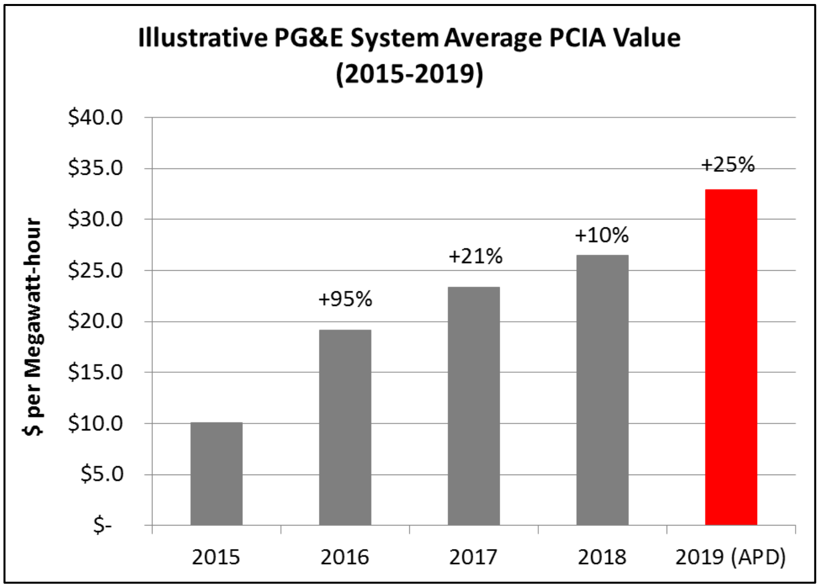
load-serving entities as part of its planning process to procure: "resources that reduce GHG emissions up to the point that the marginal cost of doing so equals the GHG Planning Price" set by the Commission at $15.17/ton in 2018, $22.19 in 2025 and then rising quickly to $150/ton in 2030. D.18-02-018 at 106, 116. Although the Commission noted that actual prices paid may not reach these levels, the adoption of these GHG targets will provide a further premium for zero-GHG resources.

[93] *See* PD at 60-62.



Finally, set in the context of the balanced solutions presented by the PD, the cap falls much closer to the resulting PCIA rates and would be applied to only the Residential, Small L&P and Agriculture classes.

If the PD's cap and collar are not adopted, the Commission should make two changes to the APD's proposed collar. First, it should maintain the status quo by holding PCIA rates at 2018 levels in 2019 to moderate volatility as the new benchmark and true-up are implemented. Second, the collar should be reduced to 10 percent to provide a more stable and predictable progression toward Phase 2.

IX. CONCLUSION

For the foregoing reasons, CalCCA requests that the Commission reject the APD and adopt the Administrative Law Judge's Proposed Decision, subject to the modifications proposed in CalCCA's August 21 comments on the PD. If, despite the legal infirmities of the APD's treatment of UOG facilities, the Commission adopts the APD, CalCCA requests adoption of the proposals herein along with its August 21 proposal for a default prepayment methodology.

Respectfully submitted,

Evelyn Kahl

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California Community Choice Association

September 6, 2018

EXHIBIT A

PROPOSED MODIFICATIONS

EXHIBIT A

PROPOSED MODIFICATIONS

Findings of Fact

4. A revised RA Adder should be ~~that is~~ calculated with separate benchmarks for system, local and flexible RA to the extent feasible. The system RA benchmark should be calculated using reported purchase and sales prices of IOU, CCA, and ESP transactions, in proportion to the percentage of total system RA used for compliance represented by such transactions. The remainder of the benchmark should be calculated using the CEC's short-term "going forward" cost of capacity value. At this point in the development of flexible capacity values, the CEC's short-term "going forward" is the best available estimate of this value. Together, these components of an RA calculation will produce reasonably accurate estimates~~, if a zero or de minimis price is assigned for capacity expected to remain unsold~~.

15. A true-up mechanism will increase the accuracy of the PCIA cost allocation between bundled and departing load customers only where actual costs and revenues from transactions are available. A true-up of the portfolio value of resources remaining to serve bundled customers will not increase accuracy because there are no actual transactions through which to obtain an "accurate" value. The true-up thus should true up generation and purchase power costs, energy costs and any associated sales revenues. ~~ensure that bundled and departing load customers pay equally for PCIA-eligible resources.~~

~~16. 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. An option to prepay would provide simplicity and predictability for departing load customers, and greater certainty in the prepayment rights and obligations would benefit departing load customers.

24. A new phase of this proceeding would enable parties to continue working together to develop a number of proposals regarding portfolio optimization and

cost reduction for future consideration by the Commission, including the sale of all or some portion of the IOUs' supply portfolios.

Conclusions of Law

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 Finding of Fact 4. ~~Appendix 1 of this decision.~~

12. Including the costs of pre-2002 Legacy UOG within the PCIA charged to CCAs violates the statutes governing CCA departing load cost responsibility. ~~is consistent with AB 117 and SB 350.~~

16. A true-up mechanism consistent with Finding of Fact 19 should be adopted to ensure greater accuracy in PCIA cost allocation between ~~that~~ bundled and departing load customers ~~pay equally for PCIA-eligible resources~~.

13. There is no justification to discontinue a 10-year limit on recovering costs for post-2002 UOG from departing load, and doing so would remove important incentives for prudent utility portfolio management ~~a limitation that does not exist for post-2002 PPAs or for pre-2002 UOG~~.

19. The PCIA should remain at current rates for 2019 and, thereafter, rates should be subject to a 10% rate of change collar commencing until Phase 2 has been fully implemented. ~~A PCIA collar with a floor and a cap should be adopted to limit the change of the PCIA from one year to the next~~.

~~20. Starting with forecast year 2020, the floor of the PCIA collar should be permanently set at 75% of the prior year's PCIA.~~

~~21. Starting with forecast year 2020, the cap level of the PCIA collar should be set at 125% of the prior year's PCIA.~~

NEW. The IOUs should be required to maintain on an ongoing basis a forecast of departing load obligations for each PCIA vintage, which should serve as the basis for a default prepayment right that can be elected by departed customers.

23. DA customers and CCAs, on behalf of their customers, should be permitted to

pre-pay their PCIA obligations, following the development and implementation of a default pre-payment methodology relying on long-term PCIA rate forecasts.~~subject to Commission approval on a case-by-case basis.~~

24. 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 to develop proposals regarding portfolio optimization and cost reduction for future consideration by the Commission, including the sale of all or some portion of the IOUs' supply portfolios.

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