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)

APPLICATION OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION, CLEANPOWERSF AND SOLANA ENERGY ALLIANCE FOR REHEARING OF DECISION 18-10-019

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November 19, 2018

TABLE OF CONTENTS

TABLE OF AUTHORITIES

Page(s)

Cases

Statutes

California Public Utilities Commission Decisions

Rules & Regulations

Other Authorities

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Pursuant to Public Utilities Code sections 1731-1732 and Rule 16 of the California Public Utilities Commission's (CPUC or Commission) Rules of Practice and Procedure, the California Community Choice Association (CalCCA), Solana Energy Alliance, and CleanPowerSF submit this Application for Rehearing of Decision (D.) 18-10-019 (Decision), which was mailed on October 19, 2018. CalCCA, CleanPowerSF and Solana Energy Alliance are referred to herein collectively as the "CCA Parties."

This application is timely filed and served on the first business day following 30 days after the Commission Decision was issued.[1]

I. INTRODUCTION AND EXECUTIVE SUMMARY

The Commission has failed to proceed in the manner required by law in rendering Decision 18-10-019 (Decision), which establishes a framework for calculating the Power Charge Indifference Adjustment (PCIA). The Decision includes costs in the PCIA that the Legislature has mandated be excluded and sets a market price benchmark that fails to reduce the investor-owned utilities' (IOUs') resource portfolio costs recovered through the PCIA by the value of the benefits received by bundled customers as required by statute. In these ways, the Decision

[1] *See* Rule 16.1(a), Commission Rules of Practice and Procedure; Cal. Pub. Util. Code, § 1731(b)(1).

artificially inflates the PCIA rate that must be paid by Community Choice Aggregation (CCA) departing load customers and thus shifts costs from bundled to departing load customers. The cost shift adversely affects CCAs and their customers, while directly benefitting the bundled customers of CCAs' competitors through an artificially reduced generation charge.

The California Constitution and the provisions of the Public Utilities Code [2] confer on the Commission broad authority to regulate IOUs under its purview. The Commission's broad authority, however, is not without bounds. The Commission's exercise of its authority is "[s]ubject to statute and due process."[3] In other words, the Commission must follow and give effect to the law in its proceedings.

In issuing Decision 18-10-019, however, it has not met these requirements. Specifically, the Commission has erred by:

1. Failing to exclude the costs of utility-owned generation (UOG) in the PCIA imposed on CCA departing load customers, contrary to statute;

2. Failing to reduce the net PCIA portfolio costs of the IOUs by the value of any benefits that remain with bundled service customers, contrary to statute; and

3. Failing to exclude from the PCIA portfolio costs that are not "unavoidable" or "attributable to" departing load customers, contrary to statute.

Moreover, the Commission has failed to make findings on key issues and has drawn conclusions without substantial evidence. As discussed in greater detail below, the CCA Parties respectfully request that the Commission grant rehearing to remedy these legal errors, in accordance with

[2] Unless otherwise indicated, all statutory references herein are to the California Public Utilities Code.

[3] Cal. Const. Art. XII, § 2.

Article 16 of the its Rules of Practice and Procedure and Public Utilities Code sections 1731 and 1732.[4]

II. REQUEST FOR EXPEDITED ACTION

The Commission should act expeditiously on this application for rehearing to prevent further impairment and disruption of California's legislatively mandated CCA program. In some cases, the Decision will result in substantial increases to PCIA rates that prevent CCAs from serving their customers at the same total generation rates that the Decision enables an IOU to charge its customers. In other cases, the PCIA rates and the surrounding uncertainty may cause other CCAs to suspend or cancel the launch of service to new customers altogether. To avoid these outcomes, the CCA Parties respectfully request that the Commission expeditiously correct the legal errors in D.18-10-019, as described below. But if the Commission is unwilling to do so, it should nevertheless move quickly on rehearing given the urgency of these issues so that the CCA Parties may promptly pursue legal remedies through a petition for writ of review by an appellate court.

III. THE DECISION ERRS BY INCLUDING UTILITY-OWNED GENERATION COSTS IN THE PCIA CHARGED TO CCA DEPARTING LOAD CUSTOMERS

The Commission summarily dispenses with CalCCA's contention that, as a matter of law, UOG costs must be excluded from the scope of PCIA-eligible costs recovered from CCA departing load. Basing its conclusion, apparently, on a case only mentioned in a footnote without analysis,[5] the Commission erroneously concludes that it does "not read section 366.2(f)

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[4] The CalCCA Parties support the Application for Rehearing of Peninsula Clean Energy Authority, Marin Clean Energy, and Sonoma Clean Power Authority of Decision 18-10-019.

[5] D.18-10-019 at 52, n. 109; *Association of California Ins. Companies v. Jones* (2017) 2 Cal.5th 376.

as an exclusive list of PCIA-eligible costs."[6] The Commission finds that reading section 366.2(f) as an exclusive list would read part of 366.2(f) and 365.2 "out of the law"[7] and "render the statute inconsistent with its own subdivision (g)."[8] Neither of these conclusions is correct. The statutory provisions at issue are easily harmonized, a task that the California Supreme Court has deemed "fundamental" in any statutory construction.[9] Even if the provisions could not be harmonized, however, the Decision errs in its application of the canons of statutory interpretation and contradicts the Legislature's intent in finding that UOG costs are recoverable through the PCIA. The CCA Parties request that the Commission reverse Conclusions of Law 12 and 13 and find that all UOG costs—both ore-2002 UOG (Legacy UOG) and post-2002 UOG costs—must be excluded from the PCIA-eligible costs recovered from CCA departing load.

A. The Legislature Has Consistently Delineated the Scope of Costs That May Be Imposed on CCA Departing Load Customers

Beginning with AB 1890 (1996)[10] and following through SB 350 (2015)[11], the Legislature has established a clear and unambiguous set of costs that may be recovered from departing load (DL) customers. Nothing in any of these statutes permits the Commission to impose the costs of UOG, regardless of the date the UOG became operational, on CCA customers. Each time the Legislature has added amounts which may be recovered through the PCIA, it has done so explicitly in statute. This indicates the Legislature's continuing intention that such increases only be done through specific statutory language. Consequently, the Commission may impose UOG-related costs on CCAs only to the extent costs fall within the

6 D.18-10-019 at 52.
7 *Id.*
8 *Id.*
9 *Wells v. Marina City Properties, Inc.* (1981) 29 Cal. 3d 781, 788.
10 Assembly Bill 1890 (Stats. 1996, ch. 854) (hereafter, AB 1890).
11 Senate Bill 350 (Stats. 2015, ch. 547) (hereafter, SB 350).

scope specified in sections 454.51(c), 454.52(c), 365.1(c)(2)(A) or 365.1(c)(2)(C). The Commission thus errs in determining that UOG costs of any kind should be included in the PCIA calculation.

1. The Legislature Permitted the Recovery of Legacy UOG Stranded Costs in AB 1890 but Directed an End to Such Recovery by 2005

AB 1890, enacted in 1996, first addressed the issue of cost recovery for utility generation assets in the context of the planned transition to a competitive market. AB 1890 allowed the utilities to recover above-market sunk costs of resources that would become uneconomic in the transition through a nonbypassable charge payable by all customers, the "Competition Transition Charge" or "CTC." The Legislature expressly included UOG within the scope of the CTC[12] and made clear its intent to fully recover any such costs by 2005.[13] In fact, in implementing AB 1890, the Commission observed: "With the exception of CTC arising from existing contracts, *no further accumulation of CTC will be allowed after 2003 and collection will be completed by 2005*."[14] The utilities were given clear notice that California was transitioning to a more competitive retail market structure and had a chance at that time to address uneconomic UOG.[15] Public Utilities Code section 367 is still in force and the Legislature has not rescinded the limits on cost recovery for UOG. In fact, there is a legitimate question as to whether *any* of the Legacy UOG costs are recoverable from *any* customers.

2. The Legislature Was Fully Aware of Legacy UOG When AB 117 Was Enacted but Declined to Include the Associated Costs in the Specific

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12 *See* Cal. Pub. Util. Code, § 367.

13 D.95-12-063 at 237.

14 *Id.* at 325 (Conclusion of Law 69)(emphasis added).

15 *See, e.g.,* D.95-12-063 at 494 ("Our proposal contemplates a five-year transition period during which some utility generation assets will remain under the ownership of the utility and our regulation, while others undergo a market valuation process and possibly a transfer of ownership."); *see also* Cal. Pub. Util. Code, §§ 367(b) and 390(c).

List of Costs That May Be Recovered from CCA Departing Load Customers

In 2002, the Legislature authorized Community Choice Aggregation through the enactment of Assembly Bill 117, which included an unambiguous directive regarding the costs that must be recovered from CCA customers to prevent a cost shift to bundled customers. The Legislature mandated a "cost-recovery mechanism to be imposed on the community choice aggregator pursuant to subdivisions (d), (e), and (f) [of section 366.2]…."[16] Those subdivisions require CCA departing load customers to bear responsibility for several specific categories of costs, including Department of Water Resources bond charges,[17] Department of Water Resources' "estimated net unavoidable electricity purchase contract costs,"[18] "unrecovered past undercollections for electricity purchases, including any financing costs,"[19] and a CCA customer's share of the electrical corporation's "[e]stimated net unavoidable electricity costs ….reduced by the value of any benefits that remain with bundled service customers."[20] AB 117 was enacted in 2002, well after the Legislature addressed the issue of UOG in AB 1890. Thus, at the time of AB 117's passing the Legislature was well aware of the existence of UOG, and whether and how such costs could be recovered from departing load. Despite the Legislature's clear awareness, nothing in AB 117 directs or permits the Commission to impose these costs on CCA customers.

CCAs have not been able to raise the inclusion of UOG in the PCIA until this rulemaking because the Commission has in individual ERRA proceedings repeatedly rejected any challenges to the methodology. The treatment of UOG for CCAs is a new issue. As discussed below in Section III, the issue of inclusion of UOG with respect to DA customers is rooted in the economics applicable at that time and the specific circumstances of DA customers when departure was first contemplated and

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16 Cal. Pub. Util. Code, § 366.2(c)(5).
17 Cal. Pub. Util. Code, § 366.2(e)(1).
18 Cal. Pub. Util. Code, § 366.2(f)(2).
19 Cal. Pub. Util. Code, § 366.2(f)(1).
20 Cal. Pub. Util. Code, §§ 366.2(g).

then suspended. Neither the policy nor the logic pertains to CCAs departing now, and those decisions should not dictate the treatment of departing CCA customers.

3. Additional Departing Load Charges Have Been Expressly and Specifically Added by the Legislature Without the Inclusion of UOG Costs

The Legislature next spoke on the cost-shift issue in 2005, enacting a resource adequacy mandate to be applied to all LSEs, including CCAs, and adding certain RA costs to the costs directed to be recovered from CCA departing load.[21] The statute provides that reasonable system and local area reliability costs incurred by a utility "shall be fully recoverable from those customers on whose behalf the costs are incurred, as determined by the commission, at the time the commitment to incur the cost is made, on a fully nonbypassable basis…."[22] To avoid duplicating its prior directive in AB 117, the Legislature required the Commission to "exclude any amounts authorized to be recovered pursuant to Section 366.2 when authorizing the amount of costs to be recovered from customers of a community choice aggregator…."[23] Direct access customers, the other class of departed load customers, were not expressly excluded from the costs authorized in section 366.2. The care given by the Legislature in framing the departing load customers from whom costs could be recovered, and referring specifically to 366.2, again suggests that the Legislature intended to limit the scope of charges assessable to CCA customers to those it had expressly specified in statute.

In 2015, in SB 350, the Legislature addressed cost shifting in adopting the requirement for Load Serving Entities (LSEs) to submit Integrated Resource Plans (IRPs). To prevent cost shifting in either direction as a result of the IRPs, the statute provides that "the net costs of any incremental renewable energy integration resources procured by an electrical corporation to satisfy the need identified in subdivision (a) are allocated on a fully nonbypassable basis consistent with the treatment

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21 Cal. Pub. Util. Code, § 380.

22 Cal. Pub. Util. Code, § 380(g).

23 *Id*.

of costs identified in paragraph (2) of subdivision (c) of Section 365.1."[24] It also permitted CCAs to propose renewable integration resources to satisfy their share of any identified need.[25]

Finally, also in SB 350, the Legislature prohibited cost shifting as a result of "additional procurement" authorized under the IRP process authorized by the statute.[26] At the same time, it made certain that the Commission's allocation of a utility's "additional procurement" costs did not disrupt the authorization in §454.51 for CCAs to "self-provide renewable integration resources."[27]

Over time, the Legislature has thus carefully framed and limited the scope of costs CCA departing load customers must bear to prevent cost shifts to bundled customers. Each time it has increased the costs that may be recovered from CCA departing load customers, the Legislature has done so via specific statutory language. Two conclusions may thus be drawn. First, the Legislature intended that any increases in departing load costs must be authorized by specific statutory language. Second, because at all times since the authorization of CCAs the Legislature has been fully aware of UOG costs, the Legislature's failure to specifically authorize the recovery of these costs from CCA departing load —in fact, the Legislature's explicit steps to distinguish DA and CCA customers—indicates its determination that such costs be excluded from the calculation.

B. Excluding UOG Costs from the PCIA Harmonizes Relevant Statutes

The cardinal rule in statutory construction is to ascertain the Legislature's intent. [28] As the court of appeal has noted, "[w]hen two statutes potentially conflict, our first task is not to declare a winner, but instead to find a way, if possible, to avoid the conflict."[29] The Decision, however, errs in failing to harmonize key statutory provisions. The Decision disagrees that

24 Cal. Pub. Util. Code, § 454.51(c).
25 Cal. Pub. Util. Code, § 454.51(d).
26 Cal. Pub. Util. Code, § 454.52(c).
27 *Id*.
28 *Young v. Haines* (1986) 41 Cal.3d 883, 894; *Coulter v. Pool* (1921) 187 Cal. 181, 185.
29 *Newark Unified School District v. Superior Court* (2015) 245 Cal.App.4th 887, 904.

366.2(f) prevents UOG costs from being included in the PCIA charge because such a conclusion would read part of Public Utilities Code sections 366.2(f) and 365.2 "out of the Law"[30] and "render the statute inconsistent with its own subdivision (g)."[31] The conclusion, however, is incorrect, as the provisions can and must be harmonized. In this case, there is no conflict.

A central objective of statutory construction is to interpret provisions so as to give effect to them all.[32] The Decision errs in finding that the provisions of section 366.2(f) conflict with the prohibitions on cost-shifts in sections 366.3(g) and 365.2. In this case, there need be no conflict because the "cost-shifting" provisions, including those in 366.2(g) and 365.2, are statements of general legislative intent. Sections 366.2(f), 380(b)(2) (regarding RA), 365.1(c)(2)(A) and (c)(2)(C), 454.51(c) (regarding IRP), and 454.52(c) (collectively, DL Charge Statutes) in contrast, detail the *mechanics* for implementing the Legislature's intent. This reading is bolstered by the obvious intent of the relevant provisions. No other reading of the statutory language harmonizes the provisions.

The Decision also errs in finding that holding the list in 366.2(f) as exclusive would read parts of sections 366.2(f) and 365.2 "out of the law."[33] As stated above, there is an obvious reading that harmonizes the two concepts; the general prohibition on cost-shifting is not, in fact, rendered ineffectual by a specific list of costs that may be included in the PCIA as a means of implementing this intent. Indeed, *the reverse is true*: if, as suggested by the Commission, *any* cost may be passed on to CCAs by virtue of the general prohibitions on cost shifting, the specific delineation of costs that may be included in the PCIA set out in 366.2(f) becomes completely ineffectual if that list can be determined entirely at the discretion of the Commission. It is a

30 D.18-10-019 at 52.
31 *Id.*
32 *Walker v. Superior Court* (1988) 47 Cal.3d 112, 131.
33 D.18-10-019 at 52.

long-standing principle of California law that "courts do not construe statutory provisions 'so as to render them superfluous'."[34] This exact rule against superfluity, relied on in the Decision, would in fact be contravened should the Commission's argument prevail.

The reading proposed by the Decision contravenes another principle it claims to follow: a statute must be interpreted "with reference to the entire scheme of law of which it is part so that the whole may be harmonized and retain effectiveness."[35] The reading of the DL Charge Statutes that harmonizes the provisions and gives effect to them all is the reading the CCA Parties have maintained all along: costs eligible for recovery from CCA departing load are limited to those expressly enumerated by the Legislature.

Ignoring this principle, the Decision claims the CCA Parties' interpretation would "subordinate a later-in-time statute to an earlier-in-time one"[36] and therefore conflict with a principle of statutory construction. Again, the Commission is in error. The cost-shifting language of SB 350 simply does not conflict with the language of 366.2(f). The two provisions can and must be harmonized, as stated above. When read, as is required, to give effect to all provisions, the statutory scheme clearly indicates that SB 350's prohibition on cost shifting is a statement of Legislative intent, easily harmonized with the specific mechanics by which such intent is to be carried out as set forth in the DL Charge Statutes.

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34 *In re J. W.* (2002) 29 Cal. 4th 200, 210 *quoting Shoemaker v. Myers* (1990) 52 Cal.3d 1, 22; *see, also Dyna-Med, Inc. v. Fair Employment & Housing Com*. (1987) 43 Cal.3d 1379, 1397 (Statutes "must be harmonized, both internally and with each other, to the extent possible" *citing California Mfrs. Assn. v. Public Utilities Com.* (1979) 24 Cal.3d 836,844, and interpretive constructions which render some words surplusage are to be avoided.)

35 *Clean Air Constituency v. State Air Resources Board* (1974) 11 Cal.3d 801, 814.

36 D.18-10-019 at 52.

C. Even If Relevant Statutes Could Not Be Harmonized, the Application of Long-Standing Principles of Statutory Interpretation Require the Exclusion of UOG Costs from the PCIA

As noted above, in California "it has long been the rule" that statutes relating to the same subject matter are to be construed together and harmonized if possible.[37] If, however, harmonization is not possible, and an ambiguity remains, courts turn to the rules of statutory interpretation. [38]

The Decision errs in the application of the rules of statutory interpretation that must be applied where multiple interpretations are possible. Under these circumstances, well-established maxims lead to the conclusions that the Legislature intended to exclude UOG costs from the list of costs recoverable from CCA departing load customers. UOG has not been added to this list by the Legislature and it may not be added by the Commission on its own initiative.

1. A General Provision Must Be Subordinated to a More Specific Provision

Even if the specific list in 366.2(f) is viewed as inconsistent with the general language of sections 366.2(g) and 365.2, the rules of statutory construction would require the specific statute to take precedence. In fact, the interpretation of 365.2 is clear if the Legislature has assumed that the Commission implemented 366.2(f) as the Legislature had directed years before—such that Legacy UOG costs are already excluded and the responsibility of other customers or shareholders. Section 1859 of the Code of Civil Procedure codifies a well-established maxim of statutory construction regarding specific provisions that conflict with general provisions: "In the construction of a statute the intention of the Legislature, and in the construction of the instrument the intention of the parties, is to be pursued, if possible; and when a general and particular

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37 *County of Placer v. Aetna Casualty & Surety Co*. (1958) 50 Cal.2d 182, 188-189.

38 *Jauregui v. City of Palmdale* (2014) 226 Cal.App.4th 781, 805.

provision are inconsistent, the latter is paramount to the former. So a particular intent will control a general one that is inconsistent with it."[39] "A specific provision relating to a particular subject will govern in respect to that subject, as against a general provision, although the latter, standing alone, would be broad enough to include the subject to which the more particular provision relates."[40] Thus, even assuming the provisions at issue here could not be reconciled, the specific list of PCIA-eligible costs provided in 366.2(f) must be considered to be a limitation on the Commission's ability to add costs to the PCIA.

2. *Expressio Unius* Leads to the Conclusion That the Legislature's Delineation of Specific Departing Load Charges Was Intended to Be Exclusive

As CalCCA has repeatedly urged, the maxim *expressio unius est exclusio alterius*—the expression of one thing implies the exclusion of others[41]—applies in this case. This maxim requires the Legislature's detailed lists of CCA departing load costs to be interpreted as an exclusive list unless a contrary legislative intent is expressed in the statute.[42] Here, there is no such contradictory legislative intent. On the contrary, and as detailed at length above, the Legislature has repeatedly indicated that additions to the short list of PCIA-eligible costs must be effectuated by specific statutory authorization. Therefore, the absence of language including UOG costs in the statutes authorizing cost recovery from CCA departing load customers must be read as further evidence of the Legislature's intent not to include them.

The Decision errs in failing to observe this maxim and in dispensing with this argument summarily. The Decision cites in a footnote to one case that discusses the *expressio unius*

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[39] Cal. Code Civ. Proc., § 1859.

[40] *People v. Superior Court* (2002) 28 Cal.4th 798, 808, quoting *Miller v. Superior Court* (1999) 21 Cal.4th 883, 895.

[41] *Dyna-Med, Inc. v. Fair Employment & Housing Com.* (1987) 43 Cal.3d 1379.

[42] *Fields v. March Fong Eu* (1976) 18 Cal.3d 322, 332; *CPF Agency Corp. v. Sevel's 24 Hour Towing Service* (2005) 132 Cal.App.4th 1034, 1049.

maxim. The cited case simply holds that the maxim does not apply in the particular circumstances in that case.[43] However, the facts of that case are distinct from the situation at issue here, where the application of *expressio unius* would be appropriate and would lead to the conclusion that UOG should be considered excluded from the DL Charge Statutes.

In *Association of California Ins. Companies v. Jones* the California Supreme Court reviewed the interplay of two provisions in the Unfair Insurance Practices Act.[44] One provision contains a list of specific business practices deemed "unfair claims settlement practices."[45] The other provision of the same statute contains a general prohibition on "[m]aking or disseminating or causing to be made or disseminated . . . any statement . . . with respect to the business of insurance or with respect to any person in the conduct of his or her insurance business, which is untrue, deceptive, or misleading, and which is known, or which by the exercise of reasonable case should be known, to be untrue, deceptive, or misleading."[46]

The Supreme Court agreed that *expressio unius* did not apply. The two provisions actually regulate different activity—one concerns unfair ***settlement practices***, and the other ***statements or representations***. Thus, the existence of a specific list of *practices* deemed unfair does not indicate the intent of the Legislature to exclude any particular type of untrue *statement.* "[T]he fact that the Legislature defined as unfair or deceptive a detailed list of specific unfair claims settlement practices in section 790.03, subdivision (h) . . . does not signal an intent to exempt any particular category of misleading statements from the broad prohibition on such statements in section 790.03, subdivision (b)."[47] In other words, the two statutes at issue address

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43 *Association of California Ins. Companies v. Jones* (2017) 2 Cal.5th 376, 398.
44 *Id.* The case concerns the Unfair Insurance Practices Act, Cal. Ins. Code, § 790, *et seq.*
45 Cal. Ins. Code, § 790.03(h).
46 Cal. Ins. Code, § 790.03(b).
47 *Association of California Ins. Companies v. Jones* (2017) 2 Cal.5th 376, 398.

different matters. The Legislature had not specifically defined what statements would be considered misleading or deceptive, so the maxim simply did not apply.

A very different situation is presented here, as the provisions in question address exactly the same matter: departing load charges. Sections 366.2(g) and 365.2 contain general statements prohibiting cost shifts between groups of customers, while the DL Charge Statutes implement this prohibition by providing a mechanism for ensuring cost-shifts do not occur. The costs which could affect a shift in contravention of sections 366.2(g) and 365.2 are those expressly allocated to CCA customers under 366.2(f). In other words, the provisions deal with *exactly* the same costs. The principle of *expressio unius* is designed for precisely this situation and should be applied here.

In fact, the factual situation in the *Jones* case is the converse of that at issue here. In *Jones* the court determined it was not required to expand the Legislature's "specific remedy" for unfair practices. The court found that the Insurance Commissioner could, however, enact regulations concerning misleading statements without adding to the specific remedies provided by the Legislature with respect to unfair practices. In this case, however, there is no way to implement the general prohibition on "cost-shifting" *without* expanding the "specific remedy" provided in the DL Charge Statutes themselves.

The *Jones* decision itself highlights the distinction between the two situations. In *Jones* the Court reiterated that the maxim did not apply to those facts. But the inference to be drawn by the maxim "arises when there is some reason to conclude an omission is the product of intentional design."[48] Unlike the situation in *Jones*, the history of the cost-shifting language at issue here demonstrates intentional design, and that the DL Charge Statutes are intended to be

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[48] *Howard Jarvis Taxpayers Assn. v. Padilla* (2016) 62 Cal.4th 486, 514.

exclusive. Thus, *exclusio unius* should be applied to bar expansion of the list of costs that may be passed on to CCA customers through the PCIA.

D. The Decision Errs by Failing to Examine Relevant Policy History Resulting in Unequal Treatment of CCA Customers

Beyond its sparse and flawed statutory analysis, the Decision rejects CalCCA's contention regarding exclusion of UOG costs from the PCIA on policy grounds:

> We cannot find a principled justification to exclude those costs for CCA customers because they are now above-market. Exclusion of those above-market costs amounts to an invitation to shift costs to bundled customers that were incurred to serve CCA customers who later departed.[49]

The Decision disregards an important history associated with UOG resources and ultimately discriminates against CCA customers in the application of its policy.

The PCIA was initially instituted to facilitate the recovery of CDWR power charges from DA customers. Assembly Bill 1X enabled the CDWR to begin to procure resources to serve the utilities' load following the energy crisis, and suspended the rights to enter into DA transactions until the CDWR "no longer supplies power hereunder."[50] In order to recover the CDWR costs from DA customers, the Commission imposed a direct access surcharge or exit fee to recover CDWR costs—the PCIA.[51] However, in imposing these costs on DA customers, the Commission recognized that other resources—UOG resources—were at that time below market.[52] Notably, DA customers explicitly asked the Commission to *include* UOG costs in the PCIA.[53] DA customers did so solely because the lower cost UOG provided a beneficial offset to the newly signed, expensive CDWR contracts. The Commission ultimately agreed with DA

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49 D.18-10-019 at 54.
50 Cal. Water Code, § 80110.
51 D.02-03-055, Finding of Fact 6, at 30.
52 D.02-11-022 at 19.
53 *Id.* at 20.

Customers that the above-market CDWR costs should be offset by including the lower cost UOG in the calculation of the PCIA.[54] There was no "principle" or citation to Legislative directive for this action; it was simply a "deal" approved by the Commission at the time: DA customers received an extension of the Legislature's date for suspension of new DA in exchange for their willingness to pay the netted PCIA.[55] CCAs, of course, were not parties to this agreement, because the first CCA did not begin service until 2010.

The Commission reexamined the issue of including utility generation in departing load charges in D.08-09-012, and again the assumption was made that UOG costs would be lower than the costs of other resources, and therefore would have a mitigating or netting effect on overall departing load charges.[56] This fact was acknowledged by PG&E, which asserted that "departing customers should not receive the benefits of existing generation after they leave bundled service."[57]

While the Commission originally included Legacy UOG in the PCIA to address the interests of DA customers, it extended theses costs unlawfully to departing CCA customers in 2004.[58] Now, however, the utilities have begun or proposed to begin removing UOG costs from the PCIA calculation *solely* for pre-2009 vintage DA customers,[59] and the Decision declines to address this issue. The Commission has permitted pre-2009 DA customers to escape these costs on the

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54 *See* D.02-11-022.

55 CalCCA Opening Brief at 33.

56 *See, e.g.*, D.08-09-012 at 49, n.52 ("For purposes of this decision, 'pre-restructuring resources' refers to those current IOU resources that existed prior to March 31, 1998 and are not subject to ongoing CTC treatment. These resources consist principally of the IOUs' retained generation (i.e., hydro, coal and nuclear plants). Power from these resources tends to be cheaper when compared to the costs related to ongoing CTC, the DWR contracts and new generation.").

57 D.08-09-012 at 49.

58 D.04-12-046.

59 Exh. AD-1 at 32; *see also* 3 Tr. 593: 6-594:18 (Fulmer): *see* D.15-12-022, Ordering Paragraph 5.

PG&E system[60] and declined to reject a settlement in the SCE General Rate Case (GRC) that deliver the same benefit to pre-2009 DA customers on its system.[61] The rationale for these actions remains unclear. The Decision states only that "the record in this docket is inadequate to disrupt the status quo for pre-2009 Direct Access customers' treatment under the PCIA," and the issue "will be addressed in A.16-04-018, and not in this proceeding."[62]

The irony, now, is that while these UOG costs originally benefited DA departing load (by reducing the PCIA), the situation is now reversed. Because the relative cost of portfolio assets has now flipped, bearing the cost of this UOG effectively burdens departing load, except today the departing load is from CCA customers. Pre-2009 DA customers received the benefits, and CCA customers receive the burden.

The Decision errs in its duplicity. If failing to include these departing load costs in CCA departing load charges will shift costs to bundled customers, as the Commission concludes,[63] why will the same failure in pre-2009 DA departing load charges have a different effect? The Legacy UOG was in place before either DA or CCA customers began to depart.[64] If the Commission finds that exclusion of Legacy UOG costs in CCA departing load charges results in a cost shift, there is simply no basis for the Commission to conclude otherwise for pre-2009 DA departing load. While the CCA Parties contend that the unequal treatment of pre-2009 DA and CCA customers is unjustifiable, the solution is not to impose these costs on pre-2009 DA customers; under these circumstances, the right solution is to remove Legacy UOG costs from the PCIA for all customers.

60 D.07-05-005.

61 *See Motion for Approval of Settlement Agreement*, dated February 1, 2018 and filed in the so-called Consolidated ERRA Docket (A.16-04-018, A.16-05-001, and A.16-06-003).

62 D.18-10-019 at 153.

63 D.18-10-019 at 56.

64 "Legacy" UOG is pre-2002 generation that was in place at the time AB 1890 was enacted, and is therefore the subject of Cal. Pub. Util. Code, § 367.

E. UOG Costs Must Be Excluded from Recovery in the PCIA Charged to CCA Departing Load Customers

The Legislature has, since 1996, expressly and specifically defined the costs that may be recovered from departing load by the investor-owned utilities. Most specifically, the Legislature defined a specific subset of utility costs that can and must be included in departing load charges under AB 117. The original list of costs has been expressly supplemented by the Legislature since the statute was passed in 2002. These express lists of recoverable costs are best harmonized with the Legislature's general policy statements regarding cost shifts in SB 350 as the mechanics of implementing its general policy; otherwise, the general statements render the specific lists "surplusage" contrary to established principles of statutory interpretation. Exclusion of UOG Costs is also supported by the history surrounding UOG resources. Moreover, the Commission's contention that the UOG costs must be recovered from all departing load to avoid cost shifts is belied by its actions permitting exclusion of these costs from the pre-2009 DA PCIA.

IV. THE DECISION CAUSES A COST SHIFT BY FAILING TO REDUCE THE NET PCIA PORTFOLIO COSTS BY THE VALUE OF ANY BENEFITS THAT REMAIN WITH BUNDLED SERVICE CUSTOMERS AS REQUIRED BY STATUTE

To prevent cost shifts, departing CCA customers must pay costs specified in subdivisions (d), (e) and (f) of section 366.2.[65] Relevant to this proceeding, subdivision (f)(2) requires such customers to pay:

> the share of the electrical corporation's estimated net unavoidable electricity purchase contract costs attributable to the customer, as determined by the commission, for the period commencing with the customer's purchases of electricity from the community choice aggregator, through the expiration of all

[65] Cal. Pub. Util. Code, § 366.2(c)(5).

> then existing electricity purchase contracts entered into by the electrical corporation.[66]

The directive does not end there. Section 366.2(g) further requires that the costs recovered from CCA customers "be reduced by the v*alue of any benefits that remain with bundled service customers*, unless the customers of the community choice aggregator are allocated a fair and equitable share of those benefits."[67] Failure to comply with the statute results in a cost shift from bundled customers to departing load customers.[68]

The Decision is devoid of any discussion of this statutory requirement[69] and makes no express findings of fact or conclusions of law regarding its satisfaction of the requirement. On its face, the Decision thus fails to comply with section 1701.2(e), which requires decisions to be "supported by findings of fact on all issues material to the decision…." Section 1701.2(e) also requires that the decision be supported by the record. The CCA Parties contend that the record fails to demonstrate that the adopted benchmark meets the requirement of section 366.2(g). This failure taints both the adopted capacity benchmark, the Decision's rejection of the GHG-free resource premium, and the overlooked ancillary services value.

The Decision thus is contrary to law, fails to provide adequate findings of fact and conclusions of law, and fails to conform to the record in this proceeding.

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66 *Id.* § 366.2(f)(2).
67 *Id.* § 366.2(g) (emphasis added).
68 S*ee* CalCCA Opening Brief at 6.
69 Decision 18-10-019 at 16.

A. The Decision Shifts Costs to Departing Load Customers by Failing to Reduce Net Portfolio Costs to Account for Capacity Costs Remaining in the Bundled Portfolio

1. The Market Price Benchmark Fails to Account for Long-Term Value of Capacity Retained by Bundled Customers

CalCCA provided extensive testimony demonstrating that utility-owned generation and long-term contracts have a long-term value that exceeds the price at which attributes are trading in the short-term market.[70] The Decision observes: "CalCCA's fundamental point is that long-term resources should be valued using long-term valuation measures…."[71] UCAN[72] and POC[73] likewise highlighted the long-term value of resources retained for bundled customers. In fact, the Commission has recognized in several different settings the existence of long-term resource value in the utilities' portfolios.[74] Despite the substantial evidence supporting the existence of long-term value, the Decision rejects CalCCA's long-term valuation proposals, choosing instead to rely on a shallow, unreliable short-term value measure.

By abdicating its obligation to value the capacity that remains with bundled customers, the Decision openly allows a cost shift from bundled to departing load customers. The Decision thus violates 366.2(g), which requires net costs to be reduced by portfolio value, ignores substantial evidence, and is an abuse of the Commission's discretion.

The Decision rejects CalCCA's proposal to recognize the long-term value of capacity based on a failure to "prove" that value:

> We do not dismiss the analysis and contentions of POC and other parties regarding the question of whether the current benchmarks completely capture the long-term value of portfolio resources. At the same time, these parties have had

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70 *See, e.g.,* CalCCA Opening Brief at 42-52, 53-61.
71 D. 18-09-019 at 18.
72 *See* UCAN Opening Brief at 20-23.
73 POC Opening Brief at 6.
74 *Infra* at 23.

difficulty proving that this is the case. We are left to base our decision on what we are able to observe and verify.[75]

In essence, the Commission recognizes the potential that there is a long-term value, but declines to act because it cannot get comfortable with any of the many values CalCCA offered for consideration. The following table shows a range of capacity values estimated by the Commission, the Energy Commission and the CAISO for various proceedings.[76]

Table 2A-3

Comparison to Marginal Cost/Market Values Indicators Across CPUC/CEC Proceedings									
Proceeding	Utility / Region	Model / Source	Capacity $ /kW-Yr	Energy $/MWH	Ancillary Service $/MWH	RPS Cost $/MWH	RPS Premium $/MWH	GHG Value $/tonne	GHG Value $/MWH
PG&E 2018 ERRA	PG&E	ERRA Table 9.5	$58.27	$33.77		$61.47	$24.16		
SCE 2018 ERRA	SCE	ERRA WPs	$58.27	$32.37		$61.47	$25.11		
PG&E 2017 GRC	PG&E	MC/RA WPs	$28.64	$28.30					
SCE 2018 GRC	SCE	MC/RA WPs	$146.85	$36.81					
EE / DRP / LIEE / NEM / DG	North	E3 Avoided Cost Calculator	$113.74	$28.03		$79.90	$14.17	$66.37	$29.15
	South		$109.75	$28.06		$79.90	$14.17	$66.37	$29.15
CEC Title 24	SF CZ 3	2016 TDV Update Model	$145.75	$37.75	$0.19	$126.00	$19.50	$15.72	$9.43
	Fresno CZ 12		$130.54	$37.75	$0.19	$129.90	$19.50	$15.72	$9.43
	LA/SD--CZ 7		$105.70	$38.01	$0.19	$129.90	$19.50	$15.72	$10.31
	LA/SD--CZ 10		$145.58	$38.01	$0.19	$129.90	$19.50	$15.72	$10.31
DCPP Retirement	PG&E	DCPP WPs				$85.62			
CAISO	CAISO	2017 MMC	$74.28	$32.97	$0.54			$12.83	$5.45

Notwithstanding the evidence introduced, instead of adopting a long-term valuation measure the Decision erroneously relies on the annual Energy Division RA Report.[77] The prices reported by the RA Report value the short-term use of a resource to provide RA capacity, which is *not the same product* as the long-term capacity embedded in the portfolio.[78] Moreover, the CCA Parties contend that the RA Report is untested, unreliable and too limited to use as a proxy for the value of 100 percent of the capacity in the utilities' portfolios. The RA Report reflects only a limited scope of products and ignores the value of bilateral contracts, the CAM allocation,

[75] D.18-10-019 at 35-36.

[76] CalCCA Opening Brief at 25 (*citing* Exh. CalCCA-1 at 2A-11-12).

[77] D.18-10-019 at 152.

[78] *See*, CalCCA Reply Brief at 15.

the CAISO CPM and the CAISO RMR mechanisms.[79] In addition, most RA is "procured via long-term PPAs rather than via short-term transactions."[80] Thus, the 2016 RA Report represents only *19.7* percent of 2016 RA—only a fraction of the actual market and of the values inherent in the products sold therein. It is therefore not suitable as a measure of the true value of capacity in the long-term utility resources in the utilities' portfolios.

The Decision's adoption of the RA Report values as a proxy for capacity retained by the utilities is a results-driven abuse of discretion, as evidenced by other Commission statements and actions. The Scoping Memo in this rulemaking recognized the potential for long-term value, requiring that the final methodology must "accurately reflect and seek to preserve all short, medium, and *long-term value of the resources procured by the utilities*…."[81] In addition, the Commission has required the utilities to use long-term values to determine the value of the retained RPS portfolio, *expressly rejecting* the use of short-term prices for this purpose.[82] CalCCA witnesses echoed this conclusion, noting that use of a short-term value for all volumes of a product in the portfolio creates distortions, stating:

> This approach implicitly assumes that the utility could replace all of those long-term volumes in the current market at the then-current short-term price. Alternatively, it assumes the utility could replace all of those long-term products with short-term products and still satisfy the Commission's expectation that the utility will provide customers a secure, reliable supply.[83]

Thus, the Decision contravenes express Commission valuation policies. It is an abuse of discretion for the Commission to, on one hand, require the use of long-term valuation and, on the other, prevent a long-term valuation for the purposes of this proceeding.

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[79] Exh. CalCCA-3 2B-3:12-17.
[80] *Id.* at 2B-3:17-21.
[81] Scoping Memo at 14 (emphasis added).
[82] Exh. CalCCA-106, The Padilla Report: Costs and Savings for the Renewables Portfolio Standard in 2016 (May 1, 2017), at 12.
[83] Exh. CalCCA-1 at 2B-4:15-2B-5:1.

Perhaps most egregiously, clear evidence demonstrates that the Commission has great depth in portfolio valuation and has regularly estimated long-term attribute values in several proceedings (*see, e.g.,* Table 2A-3 above). For example:

- The Commission has calculated avoided capacity and energy costs under the Public Utility Regulatory Policies Act of 1978 for purposes of pricing the sale of power from Qualifying Facilities to the utilities.[84]

- The Market Price Referent (MPR), a valuation tool used by the Commission in the RPS program, relies on long-term values. The MPR was implemented by the Commission as a result of SB 1078, which first enacted the RPS program.[85]

- In ratemaking, it estimates the marginal cost of various utility functions, including generation capacity. [86]

Most notably, however, the Commission calculates a long-term capacity value for both Northern and Southern California in its Avoided Cost Calculator (ACC)[87] in the Integrated Distributed Energy Resources (IDER) proceeding, R.14-10-003.[88] The purpose of the ACC is to calculate the "costs that the utility would avoid if demand-side resources produce energy in those hours. These avoided costs are the benefits that are used in determining the cost-effectiveness of these resources."[89] In short, it determines the long-term value of capacity. While the long-term capacity values estimated in the IDER proceeding may be used for a different purpose—to support the Commission's climate goals—the ACC estimates the long-term value of the *same capacity product* at issue in this proceeding.[90]

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84 *See, e.g.,* D.10-12-035.
85 *See* Ex. CalCCA-110; Senate Bill 1078 (Stats. 2002, ch. 516).
86 Application 17-06-030, Exh. SCE-04: Rate Design Proposals, filed June 30, 2017 at 96.
87 The avoided cost calculator estimates the costs of the traditional resource, normally a new combination turbine, that will be avoided when a distributed energy resource is procured instead.
88 *See* D.16-06-007.
89 *See* Exh. CalCCA-1 at 2B-7:6-10; *see*, *also* Avoided Cost Calculator User Manual, August 2016, at 1, available through "Avoided Cost User Guide" at http://www.cpuc.ca.gov/General.aspx?id=5267.
90 *See* CalCCA Opening Brief at 49.

Substantial evidence presented by CalCCA and other parties' further reveals the Commission's error. As CalCCA explained: "[u]sing long-term values for planning and the short-term benchmark for the PCIA can create an untenable fiction."[91] Providing an example using RA capacity, CalCCA noted that this fiction "suggests an asset valued at $110/kW-year in the planning process immediately loses value—dropping from $110 to $58—the moment the asset becomes operational and its costs are included in the PCIA-eligible portfolio."[92] Under the Decision, the resource is devalued to $0 if it is not immediately used for compliance or sold in a capacity market. This disconnect— between valuation used to determine if a resource should be procured and valuation used to determine the ongoing value of the resource once it becomes operational—is not rational. The premise that the ongoing value of a resource is $0 is unsustainable. For example, although the resources are to be assigned a $0 value, is it to be supposed that the CCAs could purchase these assets from the utilities for $0 each?

This approach "retains the option value of the assets for bundled customers but requires departing load to pay the cost of bearing the downside price risk for bundled customers without compensation."[93] In other words, departing load customers are paying for benefits of long-term capacity rights that are retained by bundled customers, contrary to the requirement of section 366.2(g).

Other parties agree. The IOUs admit that a short-term approach ignores the other values capacity provides, stating there is no market "to compensate for the full capacity value of post-2002 UOG resources."[94] The testimony of Dr. Woychik, on behalf of UCAN, lends further credence to the need to rely on long-term measures to value long-term resources. He explained

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91 Exh. CalCCA-1 at 2B-7:17-18.
92 *Id.* at 2B-7:18 to 2B-8:1.
93 *Id*. at 2B-5:2-5.
94 Exh. IOU-1 at 5-9:21-23.

that "[t]here is always a price premium paid to reduce long-term uncertainty, which is a major part of the hedge value inherent in bilateral contracts; spot (physical) prices have little if any hedge values, so would systematically understate bilateral contract value."[95] He went on to explain that "[b]ilateral contracts usually represent plant characteristics, which can be used and applied in multiple markets, and accordingly represent option value." He observed that "[s]everal parties, including UCAN, agree that the option value of bilateral contracts should be fully monetized and included." Ms. Kehrein, on behalf of Energy Users Forum, reinforced these observations. She concluded that "to the extent that the current method undervalues utility assets, ignores the value of optionality (hedge value), does not price all components of contract value and results in lost value," the Current Methodology cannot prevent cost shifts between bundled and departing load customers.[96] Indeed, even the Joint Utilities' witness Mr. Wan acknowledged that optionality has value.[97]

Even if, in spite of all of this evidence, the Commission believes the record contains insufficient data for it to "observe and verify" long-term capacity values, it cannot simply wash its hands of a statutory requirement without providing a path forward to eventually meeting it. The Decision complains that there seems to be a lack of "transparent price data" in the record for calculating the benefits of long-term values,[98] but it then offers no clear path in Phase 2 to find that transparency via "voluntary auction frameworks" or other mechanisms.[99] In addition, the Decision's statement that it is "continuing to pursue longer-term solutions that will more

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95 Exh. UCAN-4 at 4.
96 Exh. EUF-1 at 4:5-8.
97 1 Tr. 60:6-22 (Wan).
98 D.18-10-019 at 73-74 (discussing TURN's justification for its proposal for the capacity benchmark, which the Commission adopts stating "we find that TURN's approach to reconciling limited sources of transparent price data and developing as accurate an estimate as possible is credible").
99 *Id.* at 111.

precisely identify and capture the short, medium, and long-term value of utility resources,"[100] indicates that it has not, by definition, already reflected all "long-term value of the resources procured by the utilities." The Decision also fails to provide any guidance for the process now to be undertaken in Phase 2, which process is *required* for an accurate assessment of what values should be included in the current PCIA. For example, the Decision rejects a true-up for RA because "the recorded 'actuals' do not reflect the untransacted capacity used for bundled customer compliance,"[101] but then it does not clearly require parties to work towards a methodology to value holding that capacity for compliance purposes.

Instead, the Commission, in the face of all of its experience and the depth and breadth of testimony supporting long-term valuation, abuses its discretion and violates §366.2(g) in failing to adopt a long-term capacity value to recognize the value remaining in the bundled portfolio.

2. The Market Price Benchmark Understates Portfolio Value by Valuing Capacity Expected to Remain Unsold at Zero

Despite many parties' objections, the Decision concludes that it is "not persuaded that any of the alternatives proposed represent a better capacity benchmark than the RA Report.[102] As the RA Report tracks only capacity prices based on sales in the short term market, unsold capacity will be valued at $0. The Decision is thus in error, as it ignores substantial evidence entered into the record regarding the existence of a value to capacity beyond its short-term value, belying any potential reliance on a $0 value for "unsold" capacity.

The record is replete with testimony demonstrating the existence of long-term capacity beyond what RA may garner in the short-term market, as discussed in Section IV.A.1 above. As CalCCA witnesses noted, long term capacity resources also provide "optionality" value, which

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100 *Id.* at 129.
101 *Id.* at 141.
102 *Id.* at 152.

includes the ability to control and manage these resources, and "hedging" value, which includes the ability to offset price or market risk by entering into offsetting long-term transactions.[103] CalCCA witnesses further testified that determining the value of capacity held in the bundled portfolio using only the short-term RA market price undervalues the asset by as much as a two to one margin.[104] For example, approved long-term planning values for capacity have ranged from $102.31/kW-year in Southern California to $110.93/kW-year in Northern California for purposes of valuing distributed energy resources.[105] However, using values from the RA Report, the current PCIA values this capacity at $37.08/kW-year.[106] The Decision ignores this problem, and then exacerbates it by directing the value of "capacity expected to remain unsold" at $0.

The Commission must ask: if the "unsold" capacity has no value to bundled customers, why is the utility retaining the long-term asset at all? At a zero price, any LSE would be glad to take the assets off the utility's hands. This farcical question encapsulates the Commission's abuse of discretion in ignoring significant and substantial evidence opposing a value of $0 for capacity "expected to remain unsold."

B. The Decision Shifts Costs to Departing Load Customers By Failing to Reduce Net Portfolio Costs to Account for the Value of GHG-Free Resource Benefits Retained by the Bundled Customers

1. The Decision Errs by Concluding that the Evidence Does Not Support the Existence of a GHG-Free Premium

CalCCA proposed the adoption of a proxy to represent the value of GHG-free resources retained in the utilities' portfolios, as the Decision acknowledges.[107] "GHG-free generation carries a premium in today's market, although no reliable published market index values for this

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103 *Id*. at 57.

104 CalCCA Opening Brief at 55; *See* Exh. CalCCA-1 at 2B-4:3-6.

105 CalCCA Opening Brief at 55 (referencing Exh. CalCCA-1 at 2B-4:6-14).

106 2017 Resource Adequacy Report, Table 6, available through http://www.cpuc.cagov/RA.

107 D.18-10-019 at 139.

generation exist."[108] Having recognized the existence of such a premium, however, the Decision rejects CalCCA's proposal:

> CalCCA's position in testimony was that we should administratively apply the RPS adder to all GHG-free generation. This approach is untethered to any reliable, observable market premium. While CalCCA's advocacy on alternative amounts for such an adder has shifted, there remains a paucity of evidence in this proceeding supporting an observable, reliable market premium for this category of energy resources.[109]

The absence of a published index for GHG-free value of a resource does not excuse the Commission from failing to address the record evidence that there ***is*** a separate premium attached to GHG-free resources relative to brown power. Acknowledging the existence of a value and not including it in the PCIA benchmark implicitly acknowledges a cost shift.

CalCCA provided extensive testimony on the existence of a GHG-free premium over brown power. First, the utilities are increasingly focusing their marketing and public relations strategies on GHG-free resources, regardless of whether the GHG-free resources are RPS-eligible.[110] One of the drivers for this value adder, CalCCA's witness testified: "is its marketing value when shown in the LSE's Power Content Label."[111]

Second, PG&E's testimony in the Diablo Canyon Power Plant proceeding likewise validates a premium value for GHG-free resources. PG&E claimed that a "key element" of its proposal was that "it recognizes the value of GHG-free nuclear power as an important bridge over the next eight to nine years."[112] PG&E explained that in filling its Energy Efficiency "tranche" of GHG-free replacement resources, "[o]ffers will not be accepted unless they are

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108 Exh. CalCCA-1 at 2B-10:8-9.
109 D.18-10-019 at 150.
110 CalCCA Opening Brief at 63-64.
111 Exh. CalCCA-1 at 2B-10:9-10.
112 Exh. IOU-118, Chapter 3 at 3-1:19-20.

below a RPS eligible resource cost cap" of $82 kWh in 2016 dollars.[113] As CalCCA's witness explained, "PG&E stated the GHG-free generation from Diablo Canyon was worth considerably more than brown power, amounting to $85/MWh in 2018 dollars."[114]

Third, evidence of GHG-free resource values can be found in the summary of "External Solicitations in Which PG&E Participated (2016-2018)."[115] Of the 17 solicitations PG&E identifies, four sought proposals for "carbon-free" energy separate and apart from other forms of energy. [116]

Fourth, even the utilities acknowledge that other market participants have placed a value on GHG-free energy. The utilities explain how GHG-free transactions "are commonly traded among market participants across the Western Interconnection via voice brokers."[117] Explaining the formula used to calculate the "premium" paid for GHG-free energy versus unspecified energy (*e.g.,* brown power), they conclude that at a GHG allowance price of $14.75/metric ton, "the potential value of GHG-free energy would be $6.14/MWh,"[118] They also cite other indications of a GHG premium, from $2/MWh to $3.50/MWh.[119]

Fifth, California provides a statutory premium for the Joint Utilities for GHG-free power, including that from large hydroelectric resources. Section 454.3 provides for a premium up to a

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113 Exh. IOU-118, Chapter 4 at 4-5:17-21.
114 Exh. CalCCA-1 at 2B-11:3-5 (*citing* PG&E, Retirement of Diablo Canyon Power Plant, Implementation of the Joint Proposal, and Recovery of Associated Costs through Proposed Ratemaking Mechanisms, Testimony, A.16-08-006, pp. 4-5).
115 Exh. IOU-3, Table 3-3 at 3-11.
116 *See*, *id.* Table 3-3 at 3-11, Rows 4, 6, 7 and 13.
117 *Id*. at 2-25, n.73.
118 *Id.* Notably, the utilities also acknowledged Sonoma Clean Power and the City of San Diego's estimates of their carbon-free "premium."
119 *Id*. at 2-25:11-15.

full one percent on a utility's rate of return for investment in clean resources, mentioning in particular existing hydroelectric facilities.[120]

Sixth, the premium value has been heightened with the enactment of section 454.53(a), which provides: "It is 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 and 100 percent of electricity procured to serve all state agencies by December 31, 2045."[121]

Finally, the Commission has expressly valued this attribute already, again in the context of the IDER. It thus is entirely aware of the value of avoided GHG emissions, has recognized the value in other contexts, yet the Decision fails to address it because it does not find an observable, reliable market premium for this category of energy resources.[122]

Even opponents to the GHG-free premium implicitly or explicitly recognize the value of these resources above the brown power value. TURN acknowledged the potential GHG-free premium:

> offering a supply of PCC 1 renewable energy, GHG-free hydroelectric power and long-term renewable energy sales would provide valuable products that may command premiums over the day-ahead CAISO markets currently used as the primary basis for benchmarking the net costs of such resources.[123]

While CLECA opposed the GHG-free adder, its opposition targets the values identified by CalCCA, not the existence of a GHG-free premium.[124]

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120 § 454.3(a) provides for a return premium for investment in a facility "designed to generate electricity from a renewable resource, including, but not limited to, solar energy, geothermal steam, wind, and hydroelectric power at new or existing dams…."

121 Senate Bill 100 (Stats. 2017-2018, ch. 312, § 454.53(a)) (emphasis added).

122 D.18-10-019 at 150.

123 TURN Opening Brief at 27.

124 *See* CLECA Opening Brief at 10-11.

The evidence presented in this proceeding makes clear that there is a GHG-free value embedded in the utilities' portfolios. The Commission, on one hand, recognizes long-term values for GHG avoidance when it wants to promote a technology, yet on the other pretends it does not exist in calculating the PCIA, where it suits the purpose of reducing bundled customer costs. There could be no clearer abuse of discretion than the Commission's results-driven rejection of a GHG-premium to value the utilities' portfolios.

2. The Decision Errs by Concluding that Any GHG-Free Premium Will Be Captured in the Brown-Energy True-Up

The Decision erroneously concludes that "[a] market premium attributable to GHG-free resources, to the extent it exists, will be captured in our true-up…."[125] The Decision provides no record support for this conclusion[126] other than a very loosely related statement by the Joint Utilities:

> [d]ispatched GHG-free resources command the same market-clearing prices as all other resources, but do not have a corresponding GHG compliance cost. Accordingly, the delta between their costs and awarded revenues is larger than a fossil resource. . . . This value is already pro-ratably shared with departing load customers, as it is captured in the PCIA's 'brown' MPB when trued-up for actual market revenues.[127]

As CalCCA expressed several times during the proceeding, by suggesting that GHG-free value is somehow worked out in the brown power market, the Joint Utilities' argument equates the value of brown power with the value of GHG-free resources.[128] In the face of Senate Bill 100, it is patently obvious that the state values GHG-free or zero-emissions resources more than it values natural gas or other emitting resources. In fact, the Commission itself regularly calculates a

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125 D.18-10-019 at 150.

126 The Decision's footnote refers to CalCCA's Reply Comments on the true-up, which do not address the valuation of GHG-free resources in the utilities' portfolios. *See, id.* fn. 317.

127 D.18-10-019 at 150 (citing Joint Utilities Reply Comments at 5 and TURN Reply Brief at 18).

128 CalCCA Opening Brief at 66.

GHG-free value—apart from the value of brown power—in the IDER for purposes of estimating the value of energy efficiency.[129]

The Commission errs in suggesting that the brown power price captures GHG-free value.

C. The Decision Shifts Costs to Departing Load Customers By Failing to Reduce Net Portfolio Costs to Account for the Value of Ancillary Services

CalCCA proposed adoption of a benchmark to account for ancillary service value in the bundled portfolio, which the Decision acknowledges.[130] Although the Decision recites the views of CalCCA and other parties on this proposal,[131] it fails entirely to make findings or draw any conclusions regarding the need for an ancillary service benchmark. On its face, the Decision thus fails to comply with section 1701.2(e), which requires decisions to be "supported by findings of fact on all issues material to the decision…."

V. THE DECISION VIOLATES §366.2(F)(2) BECAUSE IT CAUSES A COST SHIFT BY INCLUDING COSTS IN THE PCIA THAT ARE NOT "ATTRIBUTABLE" OR "UNAVOIDABLE" TO DEPARTING LOAD CUSTOMERS

Public Utilities Code section 366.2(f)(2) permits the recovery of relevant costs from a CCA departing load customer only if those costs are "unavoidable" and they are "attributable" to the customers. The Scoping Memo, partly recognizing its obligation, adopted Guiding Principle 1.h., which provides that PCIA charges "should only include legitimately unavoidable costs and account for the IOUs' responsibility to prudently manage their generation portfolio and take all reasonable steps to minimize above market costs…."[132] Despite these statutory requirements, the

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129 Exh. CalCCA-1 at 2B-10:11-19.

130 *See* D.18-10-019 at 19.

131 *See, e.g.,* D.18-10-019 at 16 (Joint Utilities' GAM), 67-70 (Shell), 71-72 (UCAN), 23 (TURN). The Decision also mentions ancillary services generally in establishing the Portfolio Allocation Balancing Account (PABA). *Id.* at Ordering ¶ 7 at 161.

132 D.18-10-019 at 106 (citing Scoping Memo Guiding Principles).

Decision fails to draw any meaningful conclusions regarding whether the costs recovered in the PCIA are actually "unavoidable" and "attributable" to departing load customers.

The only conclusion regarding the Decision's compliance with this Guiding Principle lacks any detail or substance:

> We find that this principle is satisfied because we have acted in this proceeding to determine with unprecedented precision the nature of the costs incurred by the Joint Utilities, and we are initiating a second phase of this rulemaking that offers the promise of meaningful progress toward reducing the levels of above-market costs going forward.[133]

Section 366.2(f)(2) does not direct the Commission to "determine the nature of costs" recovered through the PCIA. Instead, it requires the Commission to assess whether the costs imposed on departing load are actually "unavoidable" and "attributable" to those customers. The Commission has made no effort to make findings of fact or draw conclusions of law regarding these statutory requirements, let alone determine whether the particular costs recovered through the PCIA meet these requirements.

In failing to undertake these assessments, the Commission has failed to comply with governing law and has proceeded without substantial evidence.

A. The Decision Errs by Continuing to Include in the PCIA the Costs of Ongoing Capital Additions in UOG That Are Not "Attributable" to Departing Load Customers

The PCIA recovers all UOG-related costs of keeping UOG resources available, "including fixed O&M, capital additions, ad valorem and insurance costs."[134] The CCA Parties contend that capital additions costs for UOG resources incurred *after* a load departs are not "attributable" to the departing load and, instead, represent a benefit to bundled customers.[135]

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133 *Id.* at 129.

134 Exh. CalCCA-1 at 2B-16:13-15.

135 D.18-10-019 at 134-135. *See* Exh. CalCCA-1 at 2B:16-19.

CalCCA supported this contention through extensive testimony about the value of utility plants.[136] The Decision summarily concludes:

> CalCCA's concern about ongoing costs for legacy UOG has potential merit, but lacks sufficient record support or an adequately developed test for evaluating such costs. It is possible that new investments in an old power plant may represent such a significant overhaul of the facility as to justify a "re-vintaging" of the facility. Likewise, it is possible that plant investments for certain upgrades may justify a different vintage treatment for those investments than for the underlying facility. But any such analysis must be fact-specific to the plants and spending in question, and is better suited to a GRC evaluating such spending. CalCCA's testimony and argument on this subject in this proceeding did not meet its burden of persuasion.[137]

The Decision thus implicitly acknowledges that the PCIA may include costs that are not attributable to departing load customers, but fails to act.

The Commission abused its discretion by failing to address this issue, despite the substantial evidence presented by CalCCA, while knowing it could be causing a cost shift from bundled to departing load customers.[138] Moreover, rejecting the proposal because CalCCA has not "adequately developed [a] test for evaluating such costs,"[139] departs from the Commission's approach on other issues. The Decision draws numerous policy conclusions that require implementation, but leaves the details to be developed in another phase. For example, the Decision adopts a framework for a PCIA prepayment option that would be made available to departing load customers, but specifies that the detail of the option—which it identifies in its Ordering Paragraph—for resolution in Phase 2.[140] The record certainly had sufficient evidence to demonstrate that the utilities incur ongoing costs for their UOG and that the costs may be

136 *See, e.g.*, Exh. CalCCA-1 at 2B-16-2B-19; Exh. CalCCA-3 at 2B-6-2B-8 and Table 2B-1.
137 D.18-10-019 at 135.
138 Exh. CalCCA -1at 2A-12 -2A-17, Fig. 2A-2 at 2A-15, and Fig. 2A-4 at 2A-16.
139 D.18-10-019 at 135.
140 D.18-10-019, Ordering ¶11.

uneconomic and not attributable to departing load customers.[141] The Decision thus could have directed that any costs of ongoing capital investment in UOG incurred after a customer's departure would not be placed in that customer's vintage, with Phase 2 limited to directing development of a "test."

The Commission abused its discretion in failing to adopt a policy regarding ongoing UOG capital additions, thus retaining those costs in the PCIA for customers who departed before the costs were incurred. The failure inures to the benefit of bundled customers by keeping ongoing capital investment costs in the PCIA and thus shifts costs from bundled to departing load customers.

B. The Decision Errs by Permitting Recovery of Avoidable Shareholder Returns on UOG from Departing Load Customers

CalCCA presented extensive testimony proposing UOG securitization as a means of "refinancing" UOG and thus reducing the costs paid by customers.[142] Through the use of securitization, CalCCA contended, UOG costs could be "avoided." The Decision, however, fails to direct the utilities to pursue securitization. Because section 366.2(f)(2) permits allocation of only those costs that are "unavoidable," the costs that could have been avoided—a portion of the utility's UOG return on equity—cannot be recovered through the PCIA. For this reason, the Commission erred in including the returns on UOG assets in the PCIA-eligible costs allocated to CCAs.

CalCCA's testimony explained that "[p]roceeds from the sale of securitized bonds provide a source of capital that can be used by the utilities at a much lower cost than typical

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141 Exh. CalCCA-1 at 2B-21, Table 2B-1; Exh. CalCCA-3 at 7-13:13-16 and Exhibit 7-A; CalCCA Opening Brief at 102.

142 *See, generally* CalCCA-1, Vol.2, §III and Exhibits 3-A through 3-D.

utility financing."[143] CalCCA proposed to raise capital through a bond issuance "sufficient to repay the utilities for their remaining investment in their generation facilities, the generation rate base: approximately $4.2 billion for PG&E and $1.5 billion for SCE."[144] The testimony explained that the benefits of this proposal have a net present value of $1.3 billion for PG&E and $589 million for SCE.[145] Other parties either supported this proposal or agreed that it merits consideration.[146]

Despite this substantial evidence, the Commission declines to direct the utilities to reduce their portfolio costs through securitization.[147] It concludes, without record evidence or a full discussion of its analysis:

> [W]e are cautious about the feasibility of this strategy given recently adopted legislation regarding the securitization of wildfire liability costs. [Citation.][148] It is unclear how additional utility securitizations would interact, and what implications there would be for overall utility borrowing costs. Given those uncertainties, we direct parties to focus on the abovementioned issues first.

By rejecting CalCCA's proposal to "avoid" ongoing returns on generation rate base, CCAs and ESPs – and their customers – will continue to be forced to pay the return on their competitors' investment.

The Commission should grant rehearing on this issue and modify the Decision to adopt the general principle that shareholder returns are neither attributable to nor recoverable from departing load customers through the PCIA. It may, as it did with other issues, defer the implementation mechanics to Phase 2.

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143 *Id*. at 3-6: 5-6.
144 *Id.* at 3-6: 14-16.
145 *Id.* at 3-7: 7; *see also, id.*, Exhibit 3-A.
146 *See* D.18-10-019 at 107-110.
147 *Id.* at 114.
148 The Commission cited SB 901.

C. The Decision Errs by Failing to Determine Whether the Costs Recovered through the PCIA are “Unavoidable” and “Attributable” to CCA Departing Load Customers

1. The Costs of Post-2002 UOG Costs, Which the Commission Explicitly Directed the Utilities to Manage Within a 10-year PCIA Recovery Period, Could Have Been Avoided and Should Not Be Recovered from Departing Load Customers

The Decision errs by expanding the PCIA to permit recovery of post-2002 UOG costs despite the Commission’s repeated directive to the utilities to manage these resources to avoid stranded costs. The Decision expands the PCIA by lifting the existing 10-year limit on the recovery of post-2002 UOG fossil costs without a reasonable justification.[149] This expansion removes an obligation placed previously on the utilities to manage their portfolios to prevent excess procurement and thus allows recovery of “avoidable” costs from departing load customers contrary to section 366.2(f).

The Commission first adopted the 10-year limit in 2003 in approving SCE’s Mountainview Generating Station, based on a proposal offered by TURN.[150] Mountainview was presented as a “unique opportunity” by SCE, but opposed by ORA and TURN as a “unique burden.”[151] TURN argued that “if Mountainview, Mohave, and direct access all converged simultaneously it could place bundled customers at serious risk of ‘rate shock.’” ORA further argued that Mountainview would be “too costly to ratepayers since it will come on line before it is needed and will contribute to an oversupply of capacity.” The Commission adopted TURN’s proposal to require departing load customers to pay the costs of these resources for 10 years so that “ratepayers are not overburdened during the early years of the contract with stranded costs if

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149 D.18-10-019, Conclusion of Law 13.

150 D.03-12-059 at 35 and Finding of Fact 22 at 63.

151 *Id.* at 32.

all the power is not needed…" The Commission's decision did not authorize SCE to reopen cost allocation of this resource in later years.

The Commission applied this limitation more generally in its 2004 adoption of the utilities' Long-Term Procurement Plans, extending it prospectively to all "fossil-fueled resources acquired by the utilities either directly or through contract."[152] It made clear that the limitation would apply to "utility-owned generation acquired as a result of the procurement process, commencing once the resource begins commercial operation."[153] In the next paragraph, the Commission contemplated greater flexibility for commitments under PPAs. It stated:

> As several parties have noted, limiting commitments for new resources to only ten years may still increase costs for captive ratepayers due to the need for the project developer to seek accelerated cost recovery for their investments rather than amortizing these investments over a longer time period.[154]

In describing these circumstances, the Commission said that it would "allow the utilities the opportunity to justify <u>in their applications</u>, on a case-by-case basis, the desirability of adopting a cost recovery period of longer than ten years." At the same time, it made clear that a longer term stranded cost recovery would apply to renewable resources.[155]

The Commission confirmed its position once again in 2008, retaining the 10-year limitation. The Commission explained:

> [T]he utilities can, over time, <u>adjust their load forecasts</u> and resource portfolios to mitigate the effects of DA, CCA, and any large municipalizations on bundled service customer indifference. By the end of the 10-year period, we assume the IOUs would be able to make substantial progress in eliminating such effects for customers who cease taking bundled service during that period.[156]

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152 D.04-12-048 at 61.
153 *Id.*
154 *Id.*
155 *Id.*
156 D.08-09-012 at 54-55 (emphasis added).

It further observed that the resources also may become more economic over time, suggesting that it would be to the ratepayers' benefit to hold those resources to lower total portfolio costs at a later date. It provided, however, that if the utilities "believe a cost recovery period extension is appropriate and necessary for specific non-RPS resources, they can make such requests…."[157]

In rejecting the proposals of CalCCA and other intervenors to maintain the 10-year limitation, in the face of the Commission's own prior decisions, Decision 18-10-019 misses the mark. The Decision:

- Reverses the burden of proof. Rather than requiring the utilities to make a showing to lift the limitation, the Decision concludes that the non-utility parties have the burden of proof: "[t]he parties opposing the termination of the 10-year limit have demonstrated no factual, legal, or technical error in their comments on the subject."[158]

- Rewards the utilities by releasing them from their existing obligations because to do otherwise would "simply place the burden of cost recovery on bundled customers after the 10-year limit expires."[159]

- Focuses on PG&E's Humboldt plant—a local reliability asset for which another solution to cost recovery can be found.[160]

It thus fails entirely to examine whether these costs are "unavoidable" and attributable." And while the Decision punts the issue to Phase 2, where the Commission will generally undertake "portfolio optimization,"[161] it once again provides no direction regarding examination of the utilities' conduct with respect to this issue.

The Commission addressed the 10-year limitation as a zero sum game, which it is not. Had the Commission set the scope of the proceeding to allow a review of the utility's prior actions with respect to portfolio management, the issue would not be a zero sum game between

157 *Id.* at 55 (emphasis added).
158 D.18-10-019 at 136.
159 *Id.* at 56.
160 *Id.* at 59.
161 *Id.* at 61.

bundled and departing load customers. The Commission thus erred in its failure to determine whether these or any other costs incurred were avoidable.

2. The Utilities' Failure to Manage Their Portfolios in Response to Departing Load Resulted in "Avoidable" Procurement That Cannot Be "Attributed" to CCA Departing Load

The Commission and the utilities have long been aware of the need to consider and forecast departing load in developing and implementing procurement. Notwithstanding this awareness—or, perhaps, because of such awareness—the utilities have, from the outset of CCA formation, continued to procure on behalf of CCA customers until the last possible moment such customers remain with bundled service, even when the utilities know or should have known that such customers were soon departing. The result is costs that could have been avoided and that cannot be attributed to CCA departing load.

Forecasting has been central to procurement since the energy crisis. In D.03-04-030, the Commission established an exemption from the CDWR Power Charge based on CDWR's forecast of departing load. It stated:

> It is clear that DWR, when negotiating long-term power contracts, assumed that a certain amount of customer generation departing load would occur every year and therefore did not procure long-term power for that portion of the load. ***In fact, such an assumption is based on common sense, since utilities have always faced departing load in various forms, including that caused by an economic downturn, improvements in energy efficiency and building codes, as well as installation of self-generation systems***.[162]

The Commission drew two important conclusions in this decision: first, that forecasting departing load makes "common sense," and second, if a procurement plan indicates a load departure, the departing load should be exempt from resources procured in implementing that plan.

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162 D.03-04-030 at 54 (emphasis added).

From the outset, the utilities refused to recognize the departures of CCA customers absent near certainty that a particular load would depart.[163] The result is that the utilities are overprocured,[164] even though these costs could have been avoided. Compounding the error, the utilities acknowledged that they would not have altered their procurement strategy *even if they had known of the departure*.[165] In PG&E's opinion, a reasonable portfolio manager would not have made any procurement decisions based on the potential departure of a small level of load.[166] In fact, to have any impact, PG&E concluded that the departure would need to be in the neighborhood of 10-20 percent of its load.[167] Given PG&E's admission that its procurement would not be altered until it felt that 10-20 percent of its load was imminent, the earliest CCA customers were saddled with procurement costs that could have been avoided in the first place. And also as clearly, any avoidable overprocurement that resulted cannot be considered attributable to the departing load.

The CCA Parties acknowledge that the Assigned Commissioner established a scope for the proceeding that excluded revising specific prior Commission determinations regarding the reasonableness of the IOUs' past procurement actions.[168] However, this exclusion of reconsidering *particular* past actions does not preclude a review of these same past actions to determine in this proceeding when a cost is not "unavoidable" or

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163 *See* 4 Tr. 809:20-810:3 (Cushnie); 4 Tr. 813:9-10 (Lawlor); 4 Tr. 814:13-16 (Lawlor).

164 CalCCA Opening Brief at 87.

165 Mr. Lawlor stated that "Marin as a percentage of PG&E's total load was between 0.1 percent and 0.2 percent" in 2010. *See*, 5 Tr. 853:25-854:1 (Lawlor) (in describing PG&E's decision to retain Marin in its procurement strategy).

166 5 Tr. 855:5-9 (Lawlor).

167 1 Tr. 37:17-21 (Wan).

168 *See* Scoping Memo at 19 ("As made clear at the PHC, and reiterated here, the scope of this proceeding will not include revisiting prior Commission determinations regarding the reasonableness of the IOUs' past procurement actions.").

"attributable" to departing load customers.[169] In fact, by failing to enforce the mandates of the Procurement Policy Manual[170] in this proceeding, and in failing to ensure that the utilities prudently managed their generation portfolios and took all reasonable steps to minimize above-market costs for all ratepayers, the Commission has failed to meet its statutory requirements under sections 280, 454.5, and 399.11-399.20 and thus ensure that only avoidable costs are included in the PCIA under 366.2(f)(2).

Moreover, even when presented with evidence demonstrating that the utilities' have not taken the actions required to avoid any "avoidable" costs, the Commission has failed to act. To correct its error, the Commission must (1) find that a utility's failure to reasonably forecast departing load and to take direct action in response to this forecast departing load results in "avoidable" costs that cannot be recovered from departing load customers and (2) reverse its decision to lift the 10-year limit on post-2002 UOG cost recovery through the PCIA. At a bare minimum, the Commission must permit a subsequent examination of the compliance of the PCIA-eligible costs with the requirements of section 366.2(f)(2).

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[169] While CalCCA adhered to the Scoping Memo's directive, it did, however, provide a clear record on utility actions with respect to Marin Clean Energy (MCE) demonstrating that certain procurement activity in 2010 was not attributable to MCE's departing load customers. *See* CalCCA Opening Brief at 99-101.

[170] The Procurement Policy Manual was adopted by Scoping Ruling filed on June 2, 2010 in Rulemaking 10-05-006, and is available at: http://docs.cpuc.ca.gov/PublishedDocs/EFILE/RULINGS/118826.PDF

VI. CONCLUSION

For all of the foregoing reasons, the CCA Parties request that the Commission grant rehearing of D.18-10-019 on the issues identified in this Application.

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November 19, 2018