PREPARED DIRECT TESTIMONY OF
THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION

VOLUME 1
Chapters 1, 2A and 2B

Introduction
PCIA Effectiveness in Avoiding Cost Shifts
Revising the Current PCIA Methodology
(Common Outline §I, §II.A, §II.B)
ORDER INSTITUTING RULEMAKING TO REVIEW, REVISE, AND CONSIDER ALTERNATIVES TO THE POWER CHARGE INDIFFERENCE ADJUSTMENT
R.17-06-026

PREPARED OPENING TESTIMONY OF
THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION

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A. Application
A&G Administrative and General
AB Assembly Bill
AS Ancillary Services
BCR Bid Cost Recovery
BNI Binding Notice of Intent
CAISO California Independent System Operator
CAM Cost Allocation Mechanism
CARB California Air Resources Board
CCA Community Choice Aggregation
CCGT Combined Cycle Gas Turbine
CDWR California Department of Water Resources
CEC California Energy Commission
CPM Capacity Procurement Mechanism
CPUC California Public Utilities Commission
CRS Cost Responsibility Surcharge
CT Combustion Turbine
CTC Competition Transition Charge
D. Decision
DA Direct Access
DG Distributed Generation
DER Distributed Energy Resources
DOE US Department of Energy
DR Demand Response
EE Energy Efficiency
ERRA Energy Resource Recovery Account
ESP Electric Service Provider
GHG Greenhouse Gas
GRC General Rate Case
IEPR Integrated Energy Resource Plan
IOU Investor Owned Utility
LCBF Least Cost Best Fit
LSE Load Serving Entity
LTTP Long Term Procurement Plan
MCP Market Clearing Price
MPB Market Price Benchmark
NBC Non Bypassable Charge
<table>
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<th>Abbreviation</th>
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<td>NPC</td>
<td>Nevada Power Company</td>
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<td>TPM</td>
<td>Third Party Manager</td>
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<td>Utility Owned Generation</td>
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<td>URG</td>
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CALIFORNIA COMMUNITY CHOICE ASSOCIATION

CHAPTER 1

INTRODUCTION

(Common Outline §I)
I. INTRODUCTION

The Power Charge Indifference Adjustment reflects the costs of the utilities’ PCIA-eligible portfolios, which are paid by all customers – bundled utility, Community Choice Aggregation and Direct Access customers. In this proceeding, the Commission must entertain two opposing views of these costs: either the investor-owned utility resource portfolios are wildly “out of the money” or the benchmark used to evaluate market value requires reform.

Applying the PCIA market-price benchmark to the utilities’ 2018 ERRA forecasts, PG&E’s portfolio is $2.2 billion (40%) “above market,” and SCE’s portfolio exceeds “market” value by $1.2 billion (35%). Using the same benchmark, the combined cost of the utility portfolios over the next twelve years would be roughly 59% – a staggering $28.1 billion\(^1\) – “above market.” Any proposals to reduce the PCIA benchmark would drive these estimates to even greater extremes. These conclusions naturally call into question utility procurement and portfolio management practices and are linked to important State policies.

CalCCA agrees that there are excess, “avoidable” costs in the utility portfolios, but supports a more rational view of the portfolios. The PCIA benchmark undervalues the resources in the utilities’ PCIA-eligible portfolios, making the portfolios appear more uneconomic than they are. This testimony offers recommendations both to reduce PCIA-eligible costs, including benefits for all customers, and to reform the PCIA benchmark to more accurately reflect the value of the utilities’ portfolios.

\(^1\) PG&E’s and SCE’s “above market” costs are estimated at $18.7 billion and $9.4 billion, respectively.
Bridging the gap between these opposing views must begin with focused efforts to reduce and slow the accrual of stranded costs in the utilities’ PCIA-eligible portfolios. CalCCA’s testimony proposes measures to reduce costs, including a proposal to remove up to $1.3 billion of costs from PG&E’s portfolio and $589 million from SCE’s portfolio through securitization of utility owned generation assets for the remaining lives of the assets. Other proposals aimed toward portfolio management and resource redistribution also present an opportunity to reduce stranded costs.

Cost reductions alone, however, do not fully close the gap. The Commission must assess the effectiveness of the current PCIA methodology in allocating PCIA-eligible costs among bundled, CCA and DA customers. CalCCA concludes in this testimony that the PCIA benchmark understates the value of capacity and “green” attributes and omits values for GHG-free attributes and ancillary services. Modifying these benchmark components, together with the proposed cost reductions, would have reduced the portion of the 2018 PCIA-eligible portfolio treated as “stranded” or “above-market” costs by roughly $1.7 billion (leaving stranded costs of $512 million) for PG&E and $908 million (leaving stranded costs of $299 million) for SCE.

The Commission and stakeholders approach these issues to fulfill the Legislature’s directives to allocate stranded costs in a manner that prevents “cost shifts”

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2 See infra, Chapter 2B, §III and Chapter 3, §III and §IV.
3 See infra, Chapter 3, Exhibit 3-A (Sutherland).
4 Id.
5 See infra, Chapter 3.
6 Throughout this testimony, we refer to net stranded costs, comparing portfolio costs and the benchmark value of the portfolio, as “Net Costs,” stranded costs, or above market costs.
7 See infra, Chapter 2A, §III.
8 Id.
from CCA customers to bundled customers and vice versa. In determining the cost responsibility of departing CCA customers, Public Utilities Code §366.2(f)(2) provides useful guidance. To prevent cost shifting from CCA customers to bundled customers, the Commission must answer three central questions:

- Is there a “net” uneconomic cost, when taking into account both costs, revenues and other benefits?
- If there is a net cost, is the cost “unavoidable,” or are there opportunities to mitigate the cost?
- If there are net unavoidable costs, did the customer cause the costs to be incurred or, in the language of the statute, is the cost “attributable to the customer”?

While the questions are simple, answering them is not, requiring an understanding of history and examination of value measures, timing, forecasting and portfolio management practices and other factors.

The utilities, CCAs and DA providers and their customers have been waiting for the opportunities presented in this rulemaking. CCAs approach this proceeding with key objectives in mind: (1) minimize costs borne by all customers; (2) protect consumers from rate shock through predictable and stable rates; (3) ensure the transparency of any solution to allocate departing load cost responsibility; (4) accurately reflect long-term and short-term value streams in the PCIA-eligible portfolios; (5) encourage prudent IOU resource procurement and portfolio management; (6) provide access for CCAs and ESPs, on a voluntary basis, to the resources in the utilities’ portfolios; and (7) enable California to continue its progress toward important environmental goals. With these objectives in mind, it is time to take account of

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changing market dynamics and find solutions that balance the interests of all
stakeholders.

II. EXECUTIVE SUMMARY OF PROPOSAL

The utilities’ PCIA-eligible resource portfolios contain “above market” costs, and
some of these costs may be avoidable. Moreover, the existing PCIA methodology
results in a cost shift from bundled customers to departing load customers, estimated
for 2018 at $492 million\textsuperscript{11} for PG&E and $25 million\textsuperscript{12} for SCE. CalCCA proposes
reforms to the existing PCIA benchmark that will substantially reduce the excess cost
burden borne by departing load customers. This testimony proposes, among other
things, to:

1. With the support of the utilities’ and other stakeholders, securitize the rate
base for all UOG committed to the utilities’ PCIA-eligible portfolios for their
remaining service lives.

2. Establish a voluntary buydown program for PCIA-eligible power purchase
agreements and, with the support of the utilities and stakeholders,
securitize the funding required to implement the program.

3. Modify the capacity value in the PCIA benchmark to blend a short-term
value for excess capacity sold into the market and, consistent with
Commission-adopted planning values, a long-term, Commission-approved
capacity value for products remaining in the portfolio.

4. Recognize the value of non-Renewable Portfolio Standard greenhouse
gas free resources in the PCIA-eligible Portfolio through the addition of a
separate benchmark component.

5. Correct the Green Adder by removing the unsupported and inaccurate
Department of Energy referents in the calculation.

6. Either exclude from the PCIA calculation any uneconomic costs of
operating UOG resources or recognize value measures missing from the
benchmark that render the operation economic.

\textsuperscript{11} See infra Chapter 2A, §III.
\textsuperscript{12} Id.
7. Correct the calculation of uneconomic costs for pumped storage facilities. Together, these modifications will reduce overall PCIA-eligible costs and realign the PCIA benchmark to more accurately reflect the value of the portfolio serving bundled customers.

CalCCA’s testimony does not stop with realignment of the PCIA methodology. It proposes consideration of a Staggered Portfolio Auction in which all of the utility’s RPS and GHG-free resources in the PCIA-eligible Portfolio would be offered for purchase by load serving entities serving bundled, CCA and DA, as well as other market participants. To the extent possible, CalCCA proposes reliance on the prices produced in the SPA to determine the “above market” costs paid by all customers, including bundled, CCA and DA customers. CalCCA further suggests changes to forecasting and portfolio management practices.

This testimony addresses other issues identified in the Scoping Memo that are important in the process of ensuring that PCIA rates are reasonable, transparent, stable and predictable over time. The testimony:

- Examines the question of “sunsetting,” from the perspective of both ending the continuing accumulation of stranded costs and ending stranded cost recovery.
- Concludes, based on an examination of future PCIA costs, that while a PCIA rate cap is not immediately necessary, the Commission should ensure an opportunity to address the question as necessary in future ERRA proceedings.
- Proposes a methodology to accommodate annual long-term PCIA forecasting as a part of the ERRA proceedings.
- Proposes a full or partial prepayment option for CCA and DA customers based on market prices produced in the SPA.
- Requests that the PCIA rate be identified as a separate line item on the bills of all customers, including bundled utility, CCA and DA customers.
Finally, the testimony examines briefly the relationship between this proceeding and the Commission’s efforts to respond to the increasingly competitive retail market. It observes that the utility’s role as Provider of Last Resort in its service territory – an issue the Commission contemplates addressing through a new rulemaking – will continue to drive the accumulation of stranded procurement costs. CalCCA urges the Commission to examine the issue in the near term, with an eye toward supporting legislative changes necessary to realign the utility’s obligation to serve with today’s market realities.

III. EVOLUTION OF DEPARTING LOAD PROCUREMENT COST RESPONSIBILITY

It would have been difficult, if not impossible, for the Commission or stakeholders to foresee two decades ago the circumstances that have led to this rulemaking. In 1994, embarking on the road to a competitive electricity market, the Commission concluded in its “Blue Book”\(^ {13}\) that “competition offers a superior means of organizing the development, delivery and consumption of services” when compared with “command-and-control and cost-of-service regulation, and government central planning.”\(^ {14}\)

Following this blueprint, the Legislature enacted Assembly Bill 1890 in 1996, which contemplated the possibility of utility divestiture of generation assets\(^ {15}\)

\(^{13}\) Order Instituting Rulemaking on the Commission’s Proposed Policies Governing Restructuring California’s Electric Services Industry and Reforming Regulation, R.94-04-041 (Blue Book). The Blue Book followed an earlier “Yellow Book” developed by the Commission’s Division of Strategic Planning in 1993, which concluded that the then-existing regulatory structure was “ill-suited to govern today’s electric services industry,” and “incompatible with the industry structure likely to emerge in ensuing decades.” California’s Electric Services Industry: Perspectives on the Past, Strategies for the Future, February 3, 1993, at 147.

\(^{14}\) Blue Book at 5-6.

anticipated a full transition to a competitive market by 2002.\textsuperscript{16} The statute allowed the utility to recover the above-market sunk costs of resources that would become uneconomic in the transition to competition through a nonbypassable charge to be paid by all electricity customers, regardless of supplier.\textsuperscript{17} In implementing AB 1890, the Commission labeled this nonbypassable charge the “Competition Transition Charge” and observed that its goal was to “get through this transition period as quickly as possible so that full competition can begin with minimal market distortions.”\textsuperscript{18} It concluded: “With the exception of CTC arising from existing contracts, \textit{no further accumulation of CTC will be allowed after 2003 and collection will be completed by 2005.}”\textsuperscript{19}

A full transition to competition did not occur. In the midst of the 2000-2001 energy crisis, the Legislature reverted to central planning for electricity procurement. AB 1X conferred on the California Department of Water Resources the obligation to procure power for utility customers\textsuperscript{20} and suspended expansion of “Direct Access” retail competition established by AB 1890.\textsuperscript{21} AB 1X provided for the reimbursement of costs to CDWR, but did not establish a nonbypassable charge that would be applied to DA

\begin{footnotesize}
\textsuperscript{16} Assembly Bill 1890, Section 1(b) (“It is the further intent of the Legislature that during a limited transition period ending March 31, 2002, to provide for all of the following: (1) Accelerated, equitable, nonbypassable recovery of transition costs associated with uneconomic utility investments and contractual obligations….).\textsuperscript{17}

\textsuperscript{17} Pub. Util. Code §367.

\textsuperscript{18} D.95-12-063, 64 CPUC 2d 1 at 60.

\textsuperscript{19} \textit{Id.} at 58 (emphasis supplied).

\textsuperscript{20} Cal. Water Code §80000 et seq.

\textsuperscript{21} Cal. Water Code §80110 (“the right of retail end use customers pursuant to Article 6 (commencing with Section 360) of Chapter 2.3 of Part 1 of Division 1 of the Public Utilities Code to acquire service from other providers shall be suspended until the department no longer supplies power hereunder.”).
\end{footnotesize}
customers. The statutory directive appeared to be based on the conclusion that since DA had been suspended, there would be no further DA departures following long-term CDWR procurement.

Despite the absence of statutory directive, the Commission elected in implementing AB 1X in 2002 to recover the CDWR contract costs from DA customers through a nonbypassable charge, which became the “DWR Power Charge.” The DWR Power Charge aimed to determine the uneconomic cost of the CDWR long-term contracts on an annual basis, using “DA In/DA Out” production cost simulations. The Commission’s 2002 decision went beyond CDWR contract costs, however, to address Legacy UOG. The Commission had determined earlier that year:

we find that California is better served by maintaining the September 20, 2001 direct access suspension date and considering a direct access surcharge or exit fee, in lieu of an earlier suspension date, to recover DWR costs from direct access customers….we believe that such a surcharge or exit fee is a viable option and a more moderate alternative to an earlier suspension.

Industrial customer groups complained that imposing above-market CDWR costs on DA customers, while giving bundled customers sole access to below-market Legacy UOG, was inequitable. The Commission recognized the tension this approach created with AB 1890:

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22 Pub. Util. Code §360.5. The statute established the California Procurement Adjustment, requiring the Commission to “determine the amount of the California Procurement Adjustment that is allocable to the power sold by the department.” It further provided that the amount would be “payable, by each electrical corporation, upon receipt by the electrical corporation of the revenues from its retail end use customers….” No provision was made in the statute for recovery of the charge on a nonbypassable basis.

23 See generally D.02-11-022.

24 D.02-11-022 at 4-5.

25 Id. at 73-74.

26 D.02-03-055 at 16-17.
Certain parties argue that the IOUs’ ability to collect utility-related costs from DA customers expired under the provisions of AB 1890 effective after March 30, 2002, and that without specific legislation, the attempt to charge such costs violates the rule on retroactive ratemaking and Public Utilities Code Section 728….These parties claim that AB1X does not give the Commission the authority to impose a new surcharge for non-DWR costs, and do not believe any other statute gives the Commission the authority to impose surcharges that are not in any way related to the delivery of electricity to DA customers.27

Relying, in part, on the Commission’s general ratemaking authority under Sections 701, 451, and 453, and with no opposition to this approach, the Commission adopted a “separate charge to cover the ongoing above-market portion of utility-related generation costs,” allowing for the netting of above-market CDWR and then-below-market Legacy UOG costs in the utility portfolio.28

Around the same time, in 2002, the Legislature broadened opportunities for retail competition in another direction, authorizing Community Choice Aggregation through Assembly Bill 117. As with Direct Access, the Legislature sought to prevent cost shifts between bundled and CCA customers.29 The statute thus expressly required CCA customers to bear cost responsibility for CDWR historical purchases, through the CDWR Bond Charge,30 and the long-term contracts negotiated by CDWR during the energy crisis,31 through the CDWR Power Charge. In addition, the Legislature required CCA customers to reimburse the utility for certain balancing accounts32 and the following utility procurement costs:

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27 D.02-11-022 at 13.
28 See id. at 4.
30 Pub. Util. Code §366.2(e)(1). The long-term contracts have since terminated.
32 Pub. Util. Code §366.2(f)(1) (“the electrical corporation’s unrecovered past undercollections for electricity purchases, including any financing costs, attributable to that customer, that the commission lawfully determines may be recovered in rates.”).
(2) Any additional costs of the electrical corporation recoverable in commission-approved rates, equal to 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 then existing electricity purchase contracts entered into by the electrical corporation.  

AB 117 was implemented by the Commission through D.04-12-046 and D.05-12-041. Decision 04-12-046 adopted a Cost Responsibility Surcharge model for CCA customers, drawing from prior nonbypassable charge decisions and models developed for DA CRS.  

It described the scope of the CRS charge, which it stated was undisputed, as follows:

Such costs include (1) costs associated with power contracts and bonds entered into by DWR during the energy crisis; (2) utility power costs, including those of utility retained generation, purchased power and other commitments in approved resource plans; and (3) CTC and historic revenue undercollections and credits applicable to the customer at the time the CCA transferred the customer.

The Commission observed: “The methodology has been subject to considerable scrutiny in other proceedings and it is reasonable to adopt it here.”

Efforts to ensure that prior methodologies aligned with the language of AB 117, however, are not apparent in the decision.

Around the same time the Commission was implementing CCA rules, the Commission authorized expansion of the Cost Responsibility Surcharge for both DA and CCA customers. In D.04-12-048, the Commission concluded that the utility may have a need to procure or invest in new long-term resources to ensure reliability or meet

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34 D.04-12-046 at 23.
35 Id. at 24.
36 Id. at 25.
RPS requirements. It further observed that these resources “may become stranded at some point” during their life. Consequently, the Commission concluded that “the utilities should be allowed to recover the net costs of these commitments from all customers, including departing customers.” For non-RPS contract resources, cost recovery was limited to the lesser of 10 years or the contract term; for non-RPS investments, recovery was limited to 10 years following commercial operations. RPS contract cost recovery was approved for the life of the contract. The Commission’s decision was implemented in D.08-09-012, establishing the “new world generation” surcharge that would apply to DA and CCA customers consistent with D.04-12-048. In 2006, the indifference calculations for the CDWR Power Charge and Legacy UOG were folded together as the Power Charge Indifference Adjustment, designed for Direct Access, with a methodology similar to what we have today. The PCIA was designed to recover, on an annual basis, the difference between a revised benchmark power cost and “the average cost of the utilities’ total portfolio, including both utility retained generation power and allocated DWR power costs, to determine the level of the indifference charge for each year.” The 2006 decision also added a capacity value in the indifference calculation, which had until then been based solely on energy costs.

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37 D.04-12-048 at 55.
38 Id. at 58.
39 Id. at 60.
40 Id., Conclusion of Law 16 at 229-30.
41 Id.
42 D.06-07-030 at 7. The decision referred to the changes as the “Prospective DA CRS Market Benchmark Methodology Revisions.”
43 Id., Ordering Paragraph 6.
44 Id. at 9-10.
In 2010, eight years following enactment of AB 117 and more than four years following full Commission implementation of CCA, Marin Clean Energy became the first CCA to implement service. The Commission and Legislature attributed the slow launch of CCAs, in part, to activities by the investor owned utilities. The Legislature observed in enacting a requirement for a utility code of conduct in SB 790:\footnote{Pub. Util. Code §707.}

The Public Utilities Commission has found that conduct by electrical corporations to oppose community choice aggregation programs has had the effect of causing community choice aggregation programs to be abandoned.\footnote{SB 790 (2012), Section 2(d).}

Following the adoption of a code of conduct in D.12-12-036, CCAs began to develop, with 20 operational or near-operational CCAs to date.\footnote{A table showing existing CCAs and their original launch dates is provided as Exhibit 1-A. D.11-12-018. The Commission also revised the Capacity Adder, eliminated CAISO load-based costs in calculating the PCIA, replaced the use of a flat MPB weighting with a weighting based on the historical utility bundled load profile, and other DA-related changes.}

The PCIA has continued to evolve. The Commission made further changes to the PCIA methodology in 2011, adding a Green Adder to the PCIA benchmark.\footnote{Id. at 10.} The Commission found that “[t]he current indifference methodology only recognizes the IOUs’ cost of renewable resources in the calculation of the Total Portfolio Cost, but does not account for the market value of renewable resources in the MPB.”\footnote{Id. at 17.} It determined that the Green Adder should reflect “prices paid by buyers and sellers in recent transactions for delivery of RPS compliant power in California for the forecast year.”

The Commission chose to rely primarily on the utilities’ costs of procuring renewable resources, weighted at 68% of the benchmark, supplemented by “western regional...
renewable energy contract premiums published by U.S. DOE” for the remaining 32%.\textsuperscript{51}

The scope of CCA and DA cost responsibility increased again in 2014, when the Commission authorized the recovery of the utilities’ energy storage procurement costs through the PCIA.\textsuperscript{52}

The PCIA has developed over many years, affected by the foregoing and many other statutes and decisions. The long, complex history forms the foundation required to understand the current PCIA methodology and to inform long-term solutions.

\textsuperscript{51} Id. at 22.

\textsuperscript{52} D.14-10-045.
Exhibit 1-A
## Exhibit 1-A

### Existing and Near-Operational Community Choice Aggregators

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<tr>
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<td>6/1/2018</td>
</tr>
<tr>
<td>East Bay Community Energy</td>
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</tr>
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<td>Solana Energy Alliance</td>
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<tr>
<td>King City Community Power</td>
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</tr>
<tr>
<td>Desert Community Energy</td>
<td>8/1/2018</td>
</tr>
<tr>
<td>San Jose Community Energy</td>
<td>9/1/2018</td>
</tr>
</tbody>
</table>
CALIFORNIA COMMUNITY CHOICE ASSOCIATION

CHAPTER 2A

PCIA EFFECTIVENESS IN AVOIDING COST SHIFTS
(Common Outline §II.A)
I. PCIA EFFECTIVENESS IN AVOIDING COST SHIFTS

AB 117 provides sound guidance on avoiding a cost shift, and this guidance should be applied in answering the Commission’s questions about whether the current PCIA methodology results in a cost shift between bundled customers and CCA and DA customers.

The term “cost shift” has been used extensively in Commission decisions and legislation but has no formal definition. Perhaps the closest the Legislature has come is AB 117, where it identified all costs for which CCA customers would bear responsibility to avoid a cost shift.¹ Among those costs, the statute addresses ongoing utility procurement, requiring CCA customers to pay:

Any additional costs of the electrical corporation recoverable in commission-approved rates, equal to 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 then existing electricity purchase contracts entered into by the electrical corporation.²

CCA customer cost responsibility arises for “purchase contract” costs that are, on a “net” basis, “unavoidable” and “attributable” to the CCA departing load customer. These three guideposts provide a reliable framework for assessing whether the departing load customer is bearing the cost responsibility required to avoid a cost shift.

The approach to analyzing cost shifts that has evolved over time departs from close adherence to these guideposts. The existing PCIA methodology “nets” procurement costs and the portfolio’s “market value” to derive a Net Cost. The current methodology also appears to assume that if a cost is in a utility portfolio and the

¹ Cal. Pub. Util. Code §366.2(e) and (f).
² Id. §366.2(f)(2).
procurement of the resource underlying the cost was initially deemed prudent by the
Commission, the cost is “unavoidable” for the duration of the PPA or the asset book life.
Finally, the utilities and the current PCIA methodology consider any plant built or
contract executed while a customer was a bundled customer “attributable” to that
customer. As discussed below, these long-standing views may appear to follow these
guideposts, but ignore important dimensions of portfolio value and the importance of
ongoing and prudent utility portfolio management.

This proceeding presents an opportunity for the Commission to clearly define the
meaning of cost shift using the guideposts expressed in Public Utilities Code
§366.2(f)(2). Focusing on the statute will enable the Commission to mitigate the risk of
cost shifts between CCA and utility bundled customers, as the Legislature intended,
with an improved process providing transparency, flexibility, accountability, and
predictability, while also lowering costs for all customers.

A. A “Cost Shift” Occurs When a Customer Does Not Shoulder the
   “Net” Unavoidable Costs Attributable to That Customer

AB 117 identifies “net” unavoidable costs as the responsibility of departing CCA
customers. While the Legislature did not explain in detail how “net” costs are derived,
the clear meaning of the words of the statute and the long history of the PCIA
development suggests a clear answer. Net Costs are the costs incurred by the utility in
procuring a resource offset by the value retained in the portfolio. While “costs” are
straightforwardly measurable, “value” can be harder to establish particularly in the
context of California’s hybrid market.

See PG&E and SCE Responses to CalCCA_002-Q14, attached as Exhibit 2A-A.
Determining portfolio value requires an examination of the products and attributes held in the PCIA-eligible portfolio and identifying term-related value. The following table compares the products and attributes recognized by the PCIA benchmark with the range of products and attributes either traded in the market or identified by the Commission of having unique value:

Table 2A-1

<table>
<thead>
<tr>
<th>Products and Attributes Recognized in the PCIA Benchmark</th>
<th>Products and Attributes with Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Brown Energy</td>
<td>Energy</td>
</tr>
<tr>
<td>Green Attribute</td>
<td>Renewable Energy</td>
</tr>
<tr>
<td>System RA</td>
<td>System RA</td>
</tr>
<tr>
<td></td>
<td>Non-RPS GHG-Free</td>
</tr>
<tr>
<td></td>
<td>Local RA</td>
</tr>
<tr>
<td></td>
<td>Flexible RA</td>
</tr>
<tr>
<td></td>
<td>RPS Integration</td>
</tr>
<tr>
<td></td>
<td>Hedge Value</td>
</tr>
<tr>
<td></td>
<td>Diversity Value (LCBF)</td>
</tr>
</tbody>
</table>

Certain of these products or attributes may also have a term-related value, which is most easily seen through the lens of capacity value. As explained in Chapter 2B, §II, the current capacity benchmark reflects only the annual unavoidable costs of maintaining a combustion turbine available to provide capacity – a short-term value measure. The value placed on capacity in the long run, as demonstrated by Commission-adopted capacity values, must reflect all costs of that resource, including the development and construction costs.

California’s hybrid markets create another layer of complexity in determining portfolio value. Wholesale power generation may be owned or controlled by both utilities and non-utility entities. Utilities recover their costs on a cost-of-service basis.
from captive customers with assured cost recovery, while non-utility competitors are at risk for cost recovery. Because utilities are not at market risk for UOG, this subset of generation may not be a part of the price-setting dynamic in the markets. In other words, if RA value from a UOG is held in the portfolio for serving bundled load, the value of that RA is never assessed by the market. The result is that the capacity “market” does not reflect the value of all capacity used to serve load.

Assessing portfolio value, one of the two components of “Net Cost,” must start with an examination of the full range of products and attributes held in the portfolio, including any term-related attributes. Additionally, in selecting the price used to represent that value in the PCIA benchmark, the assessment must recognize the effect the hybrid market has on market prices.

B. Estimating a Cost Shift Requires a Clear but Complex Set of Criteria to Determine Whether a Cost is “Unavoidable”

As with the word “net,” the Legislature chose to rely on the simple word “unavoidable” in AB 117 rather than providing an extended definition. In the context of utility planning, a cost is unavoidable when the utility, despite prudent procurement and portfolio management practices, cannot reduce or eliminate that cost. This assessment has several dimensions.

✓ Could procurement of the resources have been avoided by deferring the purchase or by substituting a better alternative?

✓ Could the utility have sold the resource to reduce the total cost of the portfolio?

✓ If the utility did sell the resource or its output, were the products, terms and conditions of the sale structured to bring the maximum value?

For the purposes of this proceeding, the Scoping Memo does not allow “revisiting prior Commission determinations regarding the reasonableness of the IOUs’ past
procurement actions.” The latter two dimensions, however, fall squarely within the scope of this proceeding. And they highlight a key distinction: A utility’s obligation does not stop with a single procurement decision, based on the best information available at the time, but involves many subsequent decisions regarding the ongoing portfolio composition base on new information regarding market developments and changes in demand. Prudent administration of contracts addresses the latter, which is explicitly including as a Guiding Principle in this proceeding. 

Fortunately, prudent administration has been clearly addressed by the Commission in setting expectations regarding the role and responsibility of the utility as provider of a public good. The CPUC’s Procurement Policy Manual, Standard of Conduct #4 regarding prudent administration of contracts reads:

In administering contracts, the utilities have the responsibility to dispose of economic long power and purchase economic short power in a manner that minimizes ratepayer costs. Once a contract has been deemed compliant with the utilities’ procurement plan, the contract is not subject to a reasonableness review. However, the administration of the contract by the utility remains subject to a reasonableness review and disallowance through ERRA proceedings.

The existence of a resource in the utility portfolio – even if the initial decision to procure it was prudent given the information available at that time – does not alleviate the utility of their responsibility to actively manage those resources to the benefit of all customers. Costs are not “unavoidable” if the utility fails to take advantage of an opportunity to recover some portion of the costs by divesting high-cost resources in a timely manner.

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4 Scoping Memo at 19.  
5 Scoping Memo, Guiding Principle 1.h: “[any PCIA methodology] 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.”  
The utilities have had opportunities to sell assets, avoiding a continuing stranded cost, as customer departure has occurred. For example, PG&E had the opportunity to sell a portion of its RPS portfolio to SCE and SDG&E in 2010 (and perhaps municipal utilities who also face an RPS mandate) as Marin Clean Energy (later MCE) exited bundled service. According to the Green Adder included in PG&E’s 2010 ERRA workpapers, a benchmark that is based on transactions for all three IOUs, PG&E could have sold MCE’s share of PG&E’s RPS portfolio for $149/MWh. Similarly, the share for Sonoma Clean Power could have been sold in 2013 for $120/MWh based on the reported ERRA index. Even if PG&E did not sell MCE’s and SCP’s portions immediately, the utility could have sold those portions for more than $92/MWh at any point before 2017. Today, however, those resources are valued by the MPB at only $82/MWh.\(^7\)

Similar opportunities have been available for other CCAs as they exited; and going forward, the utilities can prudently manage these excess resources by participating directly in the rounds of requests for offers issued by the new and existing CCAs.\(^8\) In fact, the failure of the utilities to participate in these RFOs or to offer reasonable terms and conditions could be viewed as withholding of resources from the market.

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\(^7\) PG&E, 2018 ERRA, November Update, Table 9-5.

The appropriate adjustment is to value the RPS portion of the vintaged portfolio applicable to a CCA at the green MPB in the year of the CCA’s departure. In this way, the utilities will be given the correct incentive to reduce their portfolio holdings in a manner that maximizes the value for all ratepayers. Following least cost dispatch for must-take generation with near zero operating costs does not qualify as prudent management — that is simply housekeeping.

Based on this approach, Table 2A-2 shows how the vintaged portfolios’ market values increase by using the Green Adder for the year of departure for PG&E since 2012. Because SCE’s CCAs formed later, with Lancaster first being established in 2016, these increases are minor for the moment, but SCE also should be held to the same standard going forward.

<table>
<thead>
<tr>
<th>Vintage</th>
<th>Increased Market Value</th>
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<tbody>
<tr>
<td>2012</td>
<td>$67,402,807</td>
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<tr>
<td>2013</td>
<td>$44,151,685</td>
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<tr>
<td>2014</td>
<td>$28,224,660</td>
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<tr>
<td>2015</td>
<td>$27,420,513</td>
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<tr>
<td>2016</td>
<td>$7,615,520</td>
</tr>
<tr>
<td>2017</td>
<td>$0</td>
</tr>
</tbody>
</table>

C. An Unavoidable Cost is “Attributable” to a Departing CCA or DA Customer When the Utility’s Forecast, at the Time an Irrevocable Action Was Taken to Procure the Resource, Assumed the Customer Would Remain in Bundled Service

Determining whether a cost is attributable to a departing CCA or DA customer requires a more refined analysis than simply observing that a customer was a bundled

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The CCA Parties are still working with PG&E’s pre-2013 workpapers provided in response to the ALJ’s Data Matrix to develop estimates for earlier vintages.
customer when a PPA was executed. Even if the customer was a bundled customer at the time, it may be that the forecast underlying the procurement decision assumed or should have assumed that load would depart in the future. If, for example, a 2018 forecast assumed that the departure of 5 MW of load in that year to be served by a CCA or DA, any procurement decision made in 2018 would not have been made on behalf of that 5 MW of departing load and could not be “attributable” to that 5 MW of departing load.

In addition, attribution requires a careful assessment of when a decision committing the utility to incur the cost was actually made. Assume, for example, that a customer was a bundled customer when an RPS contract for a new resource was originally signed but departed to be served by a CCA a year later. Assume further that the developer anticipated failing to meet its commercial operations date obligation under the contract, and the utility, two years after the customer departed, overlooked the developer’s failure and modified the original contract to address the problem. Under these circumstances, the contract modification date, rather than the original contract date, is a more suitable date for determining the customers on whose behalf the resource was procured. If the CCA customer had already departed when the decision to modify the contract and keep the deal alive was made, that latter decision is not “attributable” to the departing customer.

Similarly, if the IOU could have terminated a planned RPS commitment at a cost when additional load departed, provided binding notice of intent to depart or was forecasted to depart, and the IOU chose to continue that project, the decision to
continue is not “attributable” to the departing customer. The cost “attributable” to the
departing load cannot exceed the cost of terminating the contract in this example.

II. PUBLIC CLAIMS OF “MASSIVE” AND “ILLEGAL” COST SHIFTS ARE
UNSUPPORTABLE AND BASED ON ARBITRARY ASSUMPTIONS

The Joint Utilities have gone to great lengths to lead this Commission and public
opinion to the conclusion that the success of CCAs in garnering market share has
caused an “illegal” cost shift to bundled customers.\(^\text{10}\) PG&E, for example, has publicly
claimed an annual cost shift of $178 million based on its 2017 ERRA proceeding. The
flawed methodology underlying this conclusion relies on the PCIA framework used in
the 2017 ERRA but replaces the Capacity and the Green Adder benchmarks with
alternative values.\(^\text{11}\) As discussed below, the analysis is based on untenable
assumptions, and a roughly equivalent cost shift of $173 million in the other direction –
from bundled customers to departing load customers – can be calculated by changing
only two assumptions using values approved by this Commission for utility procurement
planning.

PG&E explained in a data response to CalCCA Data Request 1, Question 2, that
the estimate was performed “by comparing the 2017 PCIA system average rate using the
Commission-approved market price benchmark (MPB) to a PCIA rate calculated using
market-based inputs for the value of renewable and capacity attributes in the MPB.”

PG&E’s methodology values the utility’s entire portfolio – a portfolio dominated by long-

\(^\text{10}\) See, e.g., [https://equitablechoice.com/](https://equitablechoice.com/), which was organized by PG&E, as
acknowledged in its response to CalCCA Data Request 1, Question 1.

\(^\text{11}\) The $178 million cost shift was calculated by PG&E and is drawn from cell E78 on the
“PCIA Cost Shift Update – Final” provided in its response to CalCCA Data Request 1,
Question 2. According to PG&E, this is the calculation underlying the cost shift conclusions
stated on the “Fact Sheet” on the Equitable Choice website, [https://equitablechoice.com/fact-sheet/](https://equitablechoice.com/fact-sheet/).
term investments and renewable PPAs – at $47.78/MWh. This value is just $12.56/MWh above the $35.22/MWh benchmark price for liquidation of brown power in the spot market. In other words, PG&E valued the sum total of all renewable, greenhouse gas free, Local RA, Flexible RA and other products and attributes at only $12.56/MWh.

While this approach may calculate the liquidation value of small amounts of excess portfolio volumes in a short-term “market,” its usefulness stops there; it cannot be used to measure a “cost shift.” First, the calculation is limited to only three of the many products and attributes in the utility’s portfolio. Second, this approach does not make any attempt to assign an appropriate value to long-term products held to serve bundled customers and to achieve statewide policy goals. Third, it does not consider whether all of the costs were “unavoidable” or whether value above market prices could have been obtained for products sold in the market. Fourth, PG&E’s approach fails to consider whether the products and costs left in the portfolio are “attributable” to departing load customers.

The current PCIA market price benchmark calculation sets short-term market prices for three features: energy, capacity and RPS attributes. When alternative, Commission-approved estimates of longer term market values are used just for the capacity and RPS values, the Joint Utilities’ conclusion is flipped on its head, leading to the conclusion that costs have been shifted from bundled customers to CCA/DA customers.

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12 Id.  
13 PG&E 2017 ERRA, November Update Filing p. 27, Table 9-5.
The Commission’s E3 Avoided Cost Calculator relies on values carefully crafted and approved by the Commission for purposes of valuing demand response, energy efficiency and distributed energy resources opportunities presented to the utilities. In addition, the Commission has developed long-term planning values in other proceedings. Table 2A-3 shows the wide range in values and compares them with the current values used in the PCIA benchmark.

Table 2A-3

<table>
<thead>
<tr>
<th>Proceeding</th>
<th>Utility / Region</th>
<th>Model / Source</th>
<th>Capacity $/kW-Yr</th>
<th>Energy $/MWH</th>
<th>Ancillary Service $/MWH</th>
<th>RPS Cost $/MWH</th>
<th>RPS Premium $/MWH</th>
<th>GHG Value $/tonne</th>
<th>GHG Value $/MWH</th>
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</thead>
<tbody>
<tr>
<td>PG&amp;E 2018 ERRA</td>
<td>PG&amp;E</td>
<td>ERRA Table 9.5</td>
<td>$58.27</td>
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<td>$61.47</td>
<td>$24.16</td>
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<td></td>
</tr>
<tr>
<td>SCE 2018 ERRA</td>
<td>SCE</td>
<td>ERRA WPs</td>
<td>$58.27</td>
<td>$32.37</td>
<td>$61.47</td>
<td>$25.11</td>
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</tr>
<tr>
<td>PG&amp;E 2017 GRC</td>
<td>PG&amp;E</td>
<td>MC/RA WPs</td>
<td>$28.64</td>
<td>$28.10</td>
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<td>SCE 2018 GRC</td>
<td>SCE</td>
<td>MC/RA WPs</td>
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<tr>
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<td>$109.75</td>
<td>$28.06</td>
<td>$79.90</td>
<td>$14.17</td>
<td>$66.37</td>
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<td>CEC Title 24</td>
<td>SF CZ 3, Fresno CZ 12</td>
<td>2016 TDV Update Model</td>
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<td>$37.75</td>
<td>$0.19</td>
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<td>$15.72</td>
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<td>LA/SD--CZ 7</td>
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<td></td>
<td>$130.54</td>
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<td>$15.72</td>
<td>$10.31</td>
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<td>LA/SD--CZ 10</td>
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<td></td>
<td>$105.70</td>
<td>$38.01</td>
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<td></td>
<td></td>
</tr>
</tbody>
</table>

Making only two changes to PG&E’s calculation – substituting the Capacity and Calculator – results in a completely different story than the utilities have presented. Costs are shifted from bundled customers to departing load customers by roughly the same amount the utilities claim is being shifted in the reverse direction, as shown in Figure 2A-1.
The wide range of cost shift outcomes emphasizes the importance of re-examining and reforming the current PCIA benchmark.

III. THE CURRENT PCIA METHODOLOGY SHIFTS COSTS FROM BUNDLED TO CCA CUSTOMERS WHEN COMPARED WITH AN ANALYSIS RELYING ON COMMISSION ADOPTED RESOURCE VALUES

CalCCA’s testimony will identify proposals and recommendations that are necessary and appropriate and achieve two key results: a) reduce the overall costs of the utilities’ PCIA-Eligible portfolios, and 2) apply more appropriate market valuation benchmarks and cost attribution to the portfolios. These proposals, if implemented, would result in significant changes to the projected net costs of the utilities’ portfolio and the attribution of those costs between bundled and departing load customers.

CalCCA’s analysis, based on the utilities’ 2018 ERRAs, demonstrates that, when CalCCA’s proposed cost reduction initiatives and market-price benchmark improvements are taken into account, bundled customers currently are imposing a significant cost shift on departing load customers under the current PCIA methodology. This conclusion directly refutes the utilities’ assertions that CCA departing load is causing massive cost shifts in the other direction, from CCA customers to bundled
customers. Moreover, we believe that it forms a reasonable and appropriate basis on which the Commission can determine that CalCCA’s proposals are necessary in order to redress the costs shifts that CCA customers currently are bearing and to prevent them from persisting and growing in the future.

CalCCA’s analysis focuses on the following portfolio cost and value metrics:

- Total Generation (in GWh), reflecting the projected supply from the resources in the PCIA-Eligible portfolios
- Total Costs (in $), reflecting the projected costs the utilities will incur to obtain the supply from those resources
- Market Value (in $), reflecting the value of the marketable supply products produced by the resources in the portfolio
- Net Cost (in $), reflecting the amount by which Total Costs exceed Market Value

As detailed below and in the accompanying charts and tables, CalCCA has constructed four distinct scenarios for evaluation, each time comparing the portfolio cost and value metrics across the scenarios. In particular, this analysis uses the Net Cost metric to form conclusions about the level of potential cost shifts between bundled and departing load customers.

The analysis started with the 2018 ERRA portfolio costs and PCIA benchmark values as a baseline. For PG&E, this yields $2.2 billion in Net Costs and, for SCE, $1.2 billion. CalCCA’s proposed PCIA reform measures yield the results discussed below.

We then examined the impact of CalCCA’s proposal: (1) removing the costs of certain must-run generation from the PCIA-eligible portfolio as described in Chapter 2B (the Humboldt unit for PG&E and the Pebbly Beach unit for SCE); (2) modifying the PCIA benchmark components for capacity and the Green Adder, and adding
benchmark components for GHG-free resources and ancillary services as described in Chapter 2B; and (3) securitizing all PCIA-Eligible UOG, excluding “New World” fossil; remaining in the utilities’ portfolios as described in Chapter 3. Making these changes reduces PG&E’s Net Costs of $2.2 billion by $1.7 billion to $512 million, and SCE’s Net Costs of $1.2 billion by $908 million to $299 million.

Comparing the Net Costs resulting from CalCCA’s changes to the Net Costs produced by the utilities’ 2018 ERRA projections, and assuming the projected level of 2018 CCA departing load, the projected 2018 cost shift from bundled customers to departing CCA and DA customers would be as follows:

- **PG&E** $492 Million Cost Shift from Bundled to Departing customers.
- **SCE** $25 Million Cost Shift from Bundled to Departing customers.\(^\text{15}\)

The results of this analysis, using the lower departing load values for SCE, are shown below in Figures 2A-2, 2A-3, 2A-4 and 2A-5.

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\(^{14}\) The cost shift estimates are based on projected 2018 departing load of 40.9% for PG&E and 3.9% for SCE.

\(^{15}\) If SCE’s CCA departing load were assumed to rise to 40.9% as it is in PG&E’s territory, then the indicative 2018 cost shift for SCE would increase from $25 million to $264 million.
## PG&E PCIA-Eligible Portfolio—Impacts of CalCCA Proposals

<table>
<thead>
<tr>
<th>Portfolio Costs</th>
<th>2018 ERRA</th>
<th>Exclude Humboldt</th>
<th>Exclude Humboldt &amp; MPB Changes</th>
<th>CalCCA Proposals</th>
</tr>
</thead>
<tbody>
<tr>
<td>RPS-Eligible PPAs</td>
<td>$2,099,442</td>
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<td>Exclude Humboldt</td>
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<td>Securitization</td>
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<td><strong>Total</strong></td>
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<tr>
<th>Benchmark Value</th>
<th>2018 ERRA</th>
<th>Exclude Humboldt</th>
<th>Exclude Humboldt &amp; MPB Changes</th>
<th>CalCCA Proposals</th>
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<tr>
<td>Brown Power</td>
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<tr>
<td>Exclude Humboldt</td>
<td>$-</td>
<td>($30,904)</td>
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<tr>
<td>Add GHG-Free Value</td>
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<td>$-</td>
<td>$654,587</td>
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</tr>
<tr>
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<td>$-</td>
<td>$-</td>
<td>$474,792</td>
<td>$474,792</td>
</tr>
<tr>
<td>Add A/S Value</td>
<td>$-</td>
<td>$-</td>
<td>$10,062</td>
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</tr>
<tr>
<td>Remove DOE Adder</td>
<td>$-</td>
<td>$-</td>
<td>$66,986</td>
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<td><strong>Total</strong></td>
<td>$3,172,409</td>
<td>$3,141,504</td>
<td>$4,347,931</td>
<td>$4,347,931</td>
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| Net Costs               | $2,212,331| $2,214,162       | $1,007,735                    | $511,686        |
|                        | $1,831    | ($1,204,596)    | ($1,700,645)                  | ($492,155)      |

**Departing Load Shift @** 40.9%
### SCE PCIA-Eligible Portfolio—Impacts of CalCCA Proposals

<table>
<thead>
<tr>
<th>Portfolio Costs</th>
<th>2018 ERRA</th>
<th>Exclude Pebbly Beach</th>
<th>Exclude Pebbly Beach &amp; MPB</th>
<th>CalCCA Proposals</th>
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<tr>
<td>UOG GHG-Free</td>
<td>$ 403,205</td>
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<td>$ 403,205</td>
<td>$ 272,407</td>
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<td>UOG Other</td>
<td>$ 515,491</td>
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<td>Other PPA</td>
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<tr>
<td>Exclude Pebbly Beach</td>
<td>$ -</td>
<td>($29,074)</td>
<td>($29,074)</td>
<td>($29,074)</td>
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<tr>
<td>Securitization</td>
<td>$ -</td>
<td>$ -</td>
<td>$ -</td>
<td>($130,797)</td>
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</table>

<table>
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<tr>
<th>Benchmark Value</th>
<th>2018 ERRA</th>
<th>Exclude Pebbly Beach</th>
<th>Exclude Pebbly Beach &amp; MPB</th>
<th>CalCCA Proposals</th>
</tr>
</thead>
<tbody>
<tr>
<td>Brown Power</td>
<td>$ 313,205</td>
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<td>Green Power</td>
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<td>Add GHG-Free Value</td>
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<td>$ -</td>
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<td>$ -</td>
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<td>Remove DOE Adder</td>
<td>$ -</td>
<td>$ -</td>
<td>$ 90,301</td>
<td>$ 90,301</td>
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</table>

|                       | $ 2,255,941     | $ 2,255,941          | $ 2,873,544                 | $ 2,873,544      |
|                       | $0              | $617,603             | $617,603                    |                  |

| Net Costs             | $ 1,207,209     | $ 1,178,135          | $ 560,532                   | $ 298,938        |
|                       | ($29,074)       | ($646,677)           | ($908,271)                  |

| Departing Load Shift @| 3.9%            |                     |                            |                  |

The vast difference between CalCCA’s and PG&E’s perspective on current cost shifts underscores the need for review and reform of the existing PCIA methodology.
EXHIBIT 2A-A
QUESTION 14

Explain how PG&E determines whether procurement is undertaken “on behalf of” a particular customer or customers.

ANSWER 14

PG&E objects to this question to the extent that it calls for a legal conclusion. Notwithstanding that objection, PG&E responds as follows:

Generally, PG&E considers resources that were built or procured during the period before customers depart utility bundled service for an alternative energy service provider (or the period before a CCA provides PG&E and the CPUC with a Binding Notice of Intent (BNI) to begin alternative energy service to customers on a specific date), or otherwise are provided energy from non-utility sources, to be purchased, pro-rata, "on their behalf."

Charges to customers are assigned based on the existing vintaging rules (as set forth in D.08-09-012) where customers that depart bundled service prior to July 1 are assigned the prior year’s vintage and customers that depart on or after July 1 are assigned the current year's vintage. Generation resource commitments are assigned a vintage based on the year in which the commitment was made.
Question 02-14.: 

Explain how SCE determines whether procurement is undertaken “on behalf of” a particular customer or customers.

Response to Question 02-14.: 

Generally, SCE considers resources that were built or procured during the period before customers depart utility bundled service for an alternative energy service provider (or the period before a CCA provides SCE and the CPUC with a Binding Notice of Intent (BNI) to begin alternative energy service to customers on a specific date), or otherwise are provided energy from non-utility sources, to be purchased, pro-rata, "on their behalf." SCE's full position on this issue is set forth in the testimony supporting the Portfolio Allocation Methodology application. SCE further reserves its right to refine or change its position on this issue during the pendency of this proceeding as discovery and testimony development continue.

In D.08-09-12 the Commission adopted vintaging rules based on date of departure that apply to customers and load whereby customers leaving bundled utility service before July 1 of a year are assigned the previous year’s vintage, and are responsible for their portion of costs associated with procurement committed on their behalf through the end of the previous year, and customers leaving bundled utility service on or after July 1 are assigned the current year’s vintage, and are responsible for their portion of costs associated with procurement committed on their behalf through the end of the current year. Pursuant to D.08-09-12, generation resource commitments are vintaged based on the year in which the IOU executes a contract or the IOU begins construction of a new generation resource (see pp. 64-67).
CALIFORNIA COMMUNITY CHOICE ASSOCIATION

CHAPTER 2B

REVISING THE CURRENT PCIA METHODOLOGY
(Common Outline §II.B)
I. THE CURRENT PCIA METHODOLOGY CAN BE MODIFIED TO PROVIDE A REASONABLE ESTIMATE OF CCA/DA CUSTOMER COST RESPONSIBILITY

The Commission and stakeholders have invested many years and significant effort in developing and refining the current PCIA benchmark methodology. While the PCIA structurally made sense in the period after the energy crisis, the context has changed significantly with a shift in policy objectives, rapid evolution of technology and emergence of alternative load serving entities. The Commission must recognize these changes and improve the calculation of both PCIA-eligible costs and the PCIA benchmark.

The PCIA benchmark must recognize a broader scope of portfolio products and apply consistent, reasonable value measures for those products. Changes required to achieve these objectives include the following:

1. Modify the capacity value in the PCIA benchmark to blend a short-term value for excess capacity sold into the market and, consistent with Commission-adopted planning values, a long-term, Commission-approved capacity value for products remaining in the portfolio.

2. Recognize the value of non-Renewable Portfolio Standard greenhouse gas-free resources in the PCIA-eligible Portfolio through the addition of a separate benchmark component.

3. Correct the Green Adder by removing the unsupported and inaccurate Department of Energy referents in the calculation.

Collectively, these changes to both PCIA-eligible costs and the PCIA benchmark will result in a PCIA calculation that more accurately identifies the uneconomic or “above market” costs in the utilities’ portfolios.

Along with the benchmark modifications, PCIA-eligible costs should exclude certain costs:
a) Either exclude from the PCIA calculation any uneconomic costs of operating UOG resources or recognize value measures missing from the benchmark that render the operation economic.

b) Correct the calculation of uneconomic costs for pumped storage facilities.

Finally, this testimony examines whether Legacy UOG costs are appropriately recovered in the PCIA, observing that there is no specific statutory basis for its inclusion in the PCIA for CCA customers and that its continuing recovery could result in discrimination. This testimony does not propose removing these costs, however, provided that CalCCA’s proposals to include a GHG-free adder to the benchmark component and to make GHG-free generation available to CCAs are adopted.

II. MODIFY THE PCIA BENCHMARK FORMULATION TO BETTER ALIGN WITH PORTFOLIO VALUE

It is important to start the discussion of benchmark modifications by examining the cost responsibility the PCIA aims to allocate. Uneconomic costs – the focus of the PCIA – can be viewed as having two dimensions: (1) the costs of excess supply beyond bundled needs or (2) excess costs for the supply needed to serve bundled needs. Different approaches may be appropriate, as discussed in Section III.A, depending on which dimension of the problem is being addressed.

Determining whether a utility has excess supply is relatively straightforward, requiring an examination by product of whether the utility has more of that product than it needs to serve its load. If the utility portfolio holds excess supply, there may be a loss (or in some markets, a gain) in selling the excess product in the market. If an excess product that was purchased, for example, at $90/MWh is not needed to serve the bundled customers and is sold into the market for $40/MWh, there is an immediate loss to be measured of $50/MWh for the product when it is sold. The uneconomic cost of
that supply to be spread among customers through the PCIA is $50/MWh times the
volume of product actually sold. It is important to note, however, that in the case of
substantial excess above bundled requirements, the utility’s portfolio management
practices are brought into question.¹

To determine whether there are excess costs in the portfolio for products actually
serving the bundled load requires an estimation of the value of the products. The first
step is to identify products in the portfolio with value, whether explicit in the market or
implicit in procurement planning. Today’s benchmark recognizes three products: brown
energy, capacity, and the “green adder” for renewable energy. It is fairly straightforward
to conclude that the benchmark scope does not reflect all of the products embedded in
the utility portfolios. It fails to recognize traded products, such as GHG-free energy, as
well as implicit attributes, such as long-term supply security. The PCIA benchmark can
be improved by ensuring that it fully reflects the slate of products in the portfolio.

Once products are identified, product value must be determined. The value of
products in the portfolio could be assessed by offering the products into the market
under the same terms and conditions held by the portfolio (i.e., offering a 20-year
contract for 20 years). Alternatively, the value could be assessed by looking to the
value of products sold, again with similar terms and conditions. The Commission
adopted this approach in developing the “Green Adder,” which values long-term RPS
contracts in the portfolio at the current replacement price as measured by actual
transactions. As yet another alternative, in the absence of actual market prices for

¹ Portfolio management practices are discussed further in Chapter 3, §V.
comparable products, an administratively determined value used to guide utility procurement. The value of a product cannot reasonably be determined, however, using a market price for a product with fundamentally different attributes. An egregious conflict arises when using short-term prices to value attributes attached to resources acquired to meet long-term needs. Determining the value of long-term capacity held in the form of utility owned generation using the price obtained in the market for a one-year right to the capacity (or a series of one-year rights to capacity granted one year at a time) undervalues the asset by failing to recognize value in the long-term right. This disconnect is evident in comparing the Commission-approved long-term planning value for capacity of $102.31/kW-year for Southern California or $110.93/kW-year for Northern California to the current PCIA benchmark value of $58.27/kW-year or to the prices paid by the CAISO using its Capacity Procurement Mechanism of $75.72/kW-year. Moreover, using a short-term value for all volumes of a product in the portfolio creates other distortions. 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

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provide customers a secure, reliable supply. It also ignores the reality that LSEs must by law maintain a proportion of long-term products in their portfolio. Finally, using short-term prices for products held in the long-term portfolio 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.

Even with these guidelines, a resource’s value cannot be determined exclusively through market sales because of the hybrid nature of the California market. A substantial portion of the generation used to meet bundled needs is not exposed to market pricing. Utilities receive full cost-of-service recovery for their UOG, regardless of what the “market” price is at any time. By shielding utility-owned generation from market price exposure, the explicit “market” is not fully reflecting the value of generation. Rather, any explicit market will be a measure of the value of only “excess” supply exceeding the cost-of-service supply.

Moreover, California’s long-term procurement planning paradigm, among other influences, has kept market prices from reflecting actual market value, particularly for capacity. Long-term procurement planning by the CAISO and the Commission aims to prevent capacity scarcity and the high prices that come with such scarcity, using tools like reliability must run contracts and the CPM. In light of these objectives, prices for capacity vary widely with limited price transparency, beyond the CPM and the Commission’s administratively determined values used to authorize the utilities to procure additional resources. As discussed further below, it is anomalous for the Commission to use one value for an attribute and authorize utilities to procure additional

\[\text{Page | 2B-5}\]

\[\text{\footnotesize AB 1890 intended otherwise, in contemplating divestiture and an end-date on stranded UOG cost recovery.}\]
resources and at the very same time use a different lower number to value the same products in the IOU portfolio for purposes of determining above market costs to be charged to CCA customers. Yet this is the situation today, producing a shift of cost burden from bundled to departing load customers.

The goal, then, is to ensure that the values used in the PCIA benchmark adequately reflect the opportunity cost of excess supply and reasonably estimate the value of the products remaining in the portfolio. The Commission must consider, however, more specific statutory guidance on departing load cost responsibility, as discussed in Chapter 1, §IV.

A. Modify Capacity Values

The current PCIA reflects a capacity value in the benchmark – $58.27/kW-year for 2018 – intended to capture the value of “resource adequacy” as the capacity metric. It fails to achieve this objective, however, in two respects. First, it values all capacity – whether deployed for bundled customers over the next several decades or sold in the market tomorrow – using the same short-term benchmark. This short-term value reflects only the annual unavoidable costs of having a combustion turbine available: fixed O&M, insurance and property taxes. It does not include any long-term costs associated with capacity, such as the cost of constructing the CT. Second, the short-term benchmark does not reflect the value of an asset that has the capability to provide not only System Resource Adequacy, but Local Resource Adequacy, and Flexible Resource Adequacy and the additional costs of running those resources to meet those demands. In general, and on average, costs for those services exceed the energy-only market clearing prices in the CAISO market used to dispatch resources, so the costs for those services are additive to the capacity value. For these reasons, the PCIA
benchmark understates the value of capacity, thereby overstating above market costs and the PCIA rate.\(^5\)

The current PCIA capacity benchmark is at odds with Commission planning values for capacity. The Commission and the utilities continue to use administratively determined long-term market values for making resource procurement and management decisions. For example, the Commission uses a long-term value of capacity to assess cost-effectiveness of demand response, energy efficiency and distributed energy resources using the E3 Avoided Cost Calculator. The Calculator “produces an hourly set of values over a 30-year time horizon that represent costs that the utility would avoid if demand-side resources produce energy in those hours.”\(^6\)

Earlier versions of the E3 Calculator also have been at the center of the Long-Term Procurement Plan preparation for the utilities. One element of the avoided cost is capacity, which is valued using a combination of short- and long-term capacity values. The Calculator values long-term capacity at $102.31/kW-year for Southern California or $110.93/kW-year for Northern California, compared with the $58.27/kW-year adopted in PG&E’s and SCE’s 2018 ERRA for PCIA calculation.

Using long-term values for planning and the short-term benchmark for the PCIA can create an untenable fiction. Effectively, it 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

\(^5\) It also merits noting that the appropriate benchmark for valuing capacity and associated services appears to be changing. Recently, both SCE and PG&E chose to meet local RA requirements with energy storage and a mix of distributed energy resources, rather than a CT.

portfolio. The result is that contracts become “above market” the moment they are signed.

Apart from the problem with using short-term values for long-term capacity held in the portfolio, the current PCIA capacity value understates actual short-term values reflected in the market. The CAISO Capacity Procurement Mechanism suggests an alternative value. The CPM sets a soft offer price cap for CAISO to exercise its backstop procurement authority when shortfalls arise in RA compliance filings from LSEs and for other reasons, for a maximum of one year. This is the price recently paid by CAISO for certain purchases of RA capacity in both Northern California and Southern California for Calendar Year 2018 to correct for LSEs’ collective failure to procure sufficient RA for the 2018 year ahead RA compliance filing requirements. The price is not a planning value; it provides a transparent and variable price benchmark that accurately reflects actual transactions based on the near-term supply and demand balances for RA in both Northern California and Southern California. For calendar year 2018, CAISO exercised its authority to purchase RA capacity and engaged in actual transactions at the price cap of $75.72/kW-year, materially more than the PCIA benchmark of $58.27/kW-year.

CalCCA proposes to avoid the complexities of valuing each product in the capacity market. Instead, this testimony recommends the adoption of a single long-term capacity value and a single short-term capacity value. The long-term capacity value should be the Commission’s long-term planning assumption used in the Calculator (currently $110/kW-year for Northern California and $102/kW-year for Southern California) and should be applied to all capacity used to serve bundled load. This value
adequately reflects the long-term capability of a capacity resource to provide nearly the
full range of products (with the possible exception of Local RA). At the same time,
surplus capacity is valued at the going price in the CAISO market using the CPM
($75.72/kW-year). Using a short-term value for excess capacity sales recognizes that
capacity not needed to serve bundled load carries a lower value. The impact of this
change is to increase the 2018 PCIA benchmark value by an estimated $474.8 million
for the PG&E portfolio and $298.4 million for the SCE portfolio.

B. Add an Ancillary Services Value

The utilities hold capacity in their portfolios that provides or is capable of
providing ancillary services to support their bundled load or to sell into the market. The
current PCIA methodology does not account for this value in any discernable way. To
more accurately reflect full portfolio value, we recommend the addition of an ancillary
services component to the benchmark.

The Calculator recognizes ancillary services as a separate value in assessing the
value of demand side products, at $2.81/kW-year in Northern California and $3.46/kW-
year in Southern California. These ancillary service values are derived from the same
assessment of capacity values upon which CalCCA’s recommended long-term capacity
values were derived. We recommend using this value and applying it to all of the
resources held in the PCIA-eligible portfolio that provide ancillary services. These
resources can be identified by the presence of Automatic Generation Control, which
enables these resources to follow load. The impact of this change is to increase the

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7 See Avoided Cost Model ACC_v1.xls dated September 17, 2017, “Market Dynamics”
2018 PCIA benchmark value by an estimated $10.1 million for the PG&E portfolio and $10.4 million for the SCE portfolio.

C. Incorporate the Value of Non-RPS, GHG-Free Resources

PG&E and SCE hold nuclear and hydro generation assets in their portfolios that, while not RPS resources, carry a “GHG free” value. If the Commission elects to retain these assets in the PCIA-eligible portfolio, the PCIA benchmark must explicitly recognize the value of non-RPS,\(^8\) GHG-free resources.

GHG-free generation carries a premium in today’s market, although no reliable published market index values for this generation exist. One of the drivers for this value adder is its marketing value when shown in the LSE’s Power Content Label.

The Commission also has recognized the value of GHG-free products, apart from the RPS. The Commission values GHG-free energy efficiency at a price above that of compliant brown power in evaluating energy efficiency cost effectiveness, using $66.37/metric ton in 2018 in the Integrated Distributed Energy Resources proceeding.\(^9\) The Commission directed that this value be used as an input to the E3 Calculator and could similarly be applied to all output from all GHG-free, non-RPS resources in the utility portfolio, as well as for distributed energy resources and energy efficiency.\(^10\) This translates to a value of $29.15/MWh for energy efficiency reductions in GHG emissions.

Notably, a prime motivator for the RPS is GHG emission reduction. As the cost of renewables approaches the long-term value of GHG-emitting generation, the cost differential becomes an indicator of the GHG-free premium for non-RPS eligible resources already carry an implicit GHG value embedded in the RPS target.

\(^8\) D.17-08-022, p. 13.
\(^9\) Id., Ordering Paragraph 1 at 18.
generation as well. While the social cost of emissions may be higher, the compliance costs are capped at the RPS premium.

This conclusion is supported by PG&E. As recently as last year, PG&E stated the GHG-free generation from Diablo Canyon was worth considerably more than brown power, amounting to $85/MWh in 2018 dollars.\textsuperscript{11} On this basis, PG&E requested that the Commission require that all Diablo Canyon generation be replaced by GHG-free generation once Diablo Canyon retires. PG&E indicated that it would pay up to the full RPS cost for GHG-free generation. PG&E stated it would pay more than the cost of compliant brown power for GHG-free generation, and that only GHG-free generation should be obtained with no allowance for lower cost compliant brown power.

The Commission directed that the $29.15/MWh value be used as an input to the E3 Calculator and could similarly be applied to all output from all GHG-free, non-RPS resources in the utility portfolio. A reasonable approach, consistent with PG&E’s Diablo Canyon testimony, would be to value GHG-free resources the same as RPS generation, using a $24.16/MWh GHG-free adder for PG&E and $25.11/MWh for SCE. Thus, for PCIA purposes, the Green Adder should be applied to all the IOUs’ GHG-free generation, not just the RPS generation. The impact of this change is to increase the 2018 PCIA benchmark value by an estimated $654.6 million for the PG&E portfolio and $218.5 million for the SCE portfolio.

\textsuperscript{11} 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. We have discounted PG&E’s 2025 value of $98/MWh back to 2018.
D. Modify the Green Benchmark to Remove the Unavailable and Incorrect Department of Energy Referents

The current PCIA benchmark includes a “Green Adder” intended to capture the market value of renewable resources in the California market. The Commission, in D.11-12-018, determined that this component of the benchmark should “reflect prices paid by buyers and sellers in recent transactions for delivery of RPS-compliant power in California for the forecast year.” The current benchmark attempts to achieve this goal through weighting an average of utility RPS procurement costs and use of a US Department of Energy survey of reported renewable energy contract premiums in the western United States compiled by the National Renewable Energy Laboratory.

The methodology and data source adopted in 2011 is no longer effective or available. The DOE Green Adder in the Renewables MPB, previously used in the PCIA proposed by PG&E, is based on a selection of Utility Green Pricing Programs in the western United States provided by the Commission’s Energy Division. Programs are identified in a database from NREL for the Department of Energy. However, the source of this pricing information is unclear and in many cases the information is either out of date, inaccurate or irrelevant, including programs that should not be included in the calculation of the DOE Green Adder.

The source of the utility green pricing programs information is in doubt. The NREL page on Voluntary Green Power Procurement does not provide any detailed information on individual programs. In communications with NREL staff, they stated

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12 D.11-12-018, p. 17.
13 PG&E Testimony, Chapter 9, Attachment A, p.1.
14 See https://www.nrel.gov/analysis/green-power.html.
data on individual programs has never been distributed.\textsuperscript{15} Moreover, some of the programs that have been relied upon in ERRA proceedings are now defunct and out of date.\textsuperscript{16}

Further, data on the list indicates that it has not been updated since 2015 or perhaps even earlier. For example, a reference to Cheyenne Light, Fuel, and Power, which has operated as Black Hills Corporation since 2015, confirms this fact. Many premiums are out of date and it is likely that the list misses entirely any new programs that may have been launched in recent years.

Spot-checking the program information that is incorporated in the Green Adder by the utilities in their last ERRAs uncovered numerous inaccuracies, which included searching each program to confirm the premium pricing information. In many cases, there was no evidence of the program being available from the related utility website. Some of these programs may now be defunct. For other programs, the current information available from utility websites does not match the information provided by the Energy Division shown in PG&E’s 2018 ERRA workpapers.\textsuperscript{17}

Further, although the guidelines for calculating the DOE Green Adder clearly indicate that IOU renewable programs should not be included,\textsuperscript{18} Southern California Edison’s Green Rate program is included in the current dataset. This results in double

\textsuperscript{15} Eric O'Shaughnessy, NREL, email communication, May 25, 2017.
\textsuperscript{16} Testimony of Richard J. McCann, Ph.D. on Behalf of Sonoma Clean Power Authority (Revised), A.17-06-005, August 28, 2017, pp. 11-13.
\textsuperscript{17} See 09.ERRA_2018-Forecast_WP_PGE_20170601_Ch09-Table 9-5_PUBLIC.xlsm. For example, Cowlitz PUD’s Renewable Resource Energy is listed with a premium of 0.8¢/kWh, but the program has a premium of 1.5¢/kWh, according to its website. See Cowlitz PUD, \url{https://www.cowlitzpud.org/green-power}. Clallam County PUD’s Watts Green program is listed with a premium of 1.7¢/kWh, but the premium is only 0.3¢/kWh, according to its website. See Clallam PUD, \url{https://www.clallampud.net/watts-green-power/}.
\textsuperscript{18} Resolution E-4475.
counting of SCE’s RPS resources in the DOE Green Adder. In all, there are at least 19 discrepancies out of the 89 programs listed, excluding consideration of other programs that may have been since added. While both PG&E and SCE attempted to update this data in subsequent advice letter filings, the fact of the matter is that the DOE website was adopted as an unbiased third-party source, and there is no guarantee that the utilities have collected data from all of the applicable programs across the western United States.

Finally, the green power premium is calculated incorrectly. While most (but not all) of the identified tariffs supply 100% green power, the premium is calculated against generation mixes that contain a varying mix of brown and green power. In other words, unlike the utility RPS Premium which measures 100% green versus approximately 100% brown power, the DOE Adder measures mostly 100% green versus a varying mix of brown and green power. This error causes the DOE Adder to undervalue the retail green premium by at least $10/MWh. It is not possible to precisely measure this undervaluation without a more exacting review of the power mix for each utility that offers these programs. Such a review would defeat the purpose of using the DOE Adder as a ready metric for this valuation.

For these reasons, the current DOE/NREL portion of the green adder benchmark should be eliminated, and the benchmark should reflect only the average of utility RPS procurement costs. There is no reason why procurement by three large utilities in the

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19 Because we do not have the resources to survey the utilities in the entire Western Electricity Coordinating Council region, we have not proposed a revised value for this portion of the Green Adder in this proceeding other than to propose that the IOU RPS Green Adder be used to supersede this value.
20 Advice Letter 5151-E.
21 Advice Letter 3667-E.
California and Western market, alone, will not fully reflect a reasonable market value for their purchases. The renewables market has developed substantially since 2011 when the DOE Adder was first adopted. The utilities are direct participants in that market, constantly soliciting and negotiating purchases and sales, so their transactions should be at the market price for renewables. If the utilities are not transacting at the market-going rate, that calls into question whether they are properly managing their procurement and portfolios. The Commission does not need any more market information than what is provided from utility transactions for these reasons. The impact of this change is to increase the 2018 PCIA benchmark value by an estimated $67 million for the PG&E portfolio and $90.3 million for the SCE portfolio.

III. REDUCE THE SCOPE OF PCIA-ELIGIBLE COSTS

The PCIA benchmark is only half of the equation in ensuring that there is no cost shift occurring between bundled and departing load customers. CalCCA proposes modifications to the scope of PCIA-eligible costs. The Commission should either exclude from the PCIA calculation any uneconomic costs of operating UOG resources or recognize value measures missing from the benchmark that render the operation economic. In addition, it should correct the calculation of uneconomic costs for pumped storage facilities. Finally, if the Commission rejects CalCCA’s proposal for a GHG-free component to the PCIA benchmark and for an auction that provides CCAs access to GHG-free generation, CalCCA would support removal of Legacy UOG costs from the PCIA-eligible portfolio.
A. Remove the Costs of Uneconomic Facilities or Modify the PCIA Benchmark to Recognize Their Additional Value

The portfolio cost that the PCIA methodology compares to the PCIA benchmark includes variable costs of dispatched resources, including fuel costs and variable O&M. If those resources are out of the money – i.e., their dispatch cost is higher than the “market” price for energy in the benchmark – the utility is creating additional above market cost by their operation. If the utility is operating the resources despite their uneconomic variable cost, the Commission must presume that the resources are being dispatched to provide some additional value not reflected in the MPB, or that the operation is unreasonable. Either the plants should not be operated and the uneconomic costs reduced, or if there is some other value produced in operating the plants, it must be recognized in the benchmark.

Similarly, the PCIA includes all the incremental costs in its portfolio (whether or not all attributes are valued by a market element) of keeping UOG resources available, including fixed O&M, capital additions, ad valorem and insurance costs. If these costs, combined with the variable operating costs, are above the MPB energy and RA value, then keeping these units available is unreasonable and adding to uneconomic costs. Again, either these costs are uneconomic and unreasonable to operate, or they are being operated to provide benefits not quantified in the PCIA. Either way, the uneconomic costs associated with these resources should be reduced or the benchmark should be increased to reflect economic, reasonable operation of the facilities. Examples of these problems include Diablo Canyon, Humboldt and Helms for PG&E and Pebbly Beach and Eastwood facilities for SCE.
Diablo Canyon has incremental costs of continuing operation (fuel, O&M, A&G and capital additions) that are well above the market price benchmark for brown power. Unless, as PG&E asserted in A.16-08-006, continuing to operate Diablo Canyon provides an additional benefit from its generation being GHG free, it is not cost-effective to continue operating. In either case, it is inappropriate to include newly incurred uneconomic costs related to continuing to operate Diablo Canyon in the PCIA. Either there is no GHG value to Diablo Canyon's generation and it should not be operated or a GHG value should be included in the PCIA offsetting the alleged uneconomic costs.

Humboldt and Pebble Beach are necessary to operate as the locations they serve are isolated and cannot be supplied by other resources. Pebble Beach is literally located on an island, Catalina Island. There are no other resources available to serve Catalina. There is no excess supply on Catalina, no departing load on Catalina, and none of Pebble Beach's costs were incurred to serve departed load customers. In addition, if it were not for CPUC regulation, SCE could sell the output from Pebble Beach at any price it chooses, as there are no alternatives for the customers on Catalina. However, SCE included the $26.4 million annual costs of Pebble Beach in its 2018 PCIA calculation but as far as CalCCA can discern did not include any value applicable to the PCIA benchmark value — implying that the entire $26.4 million cost of Pebble Beach is uneconomic for purposes of the PCIA valuation. All forecast uneconomic costs associated with Pebble Beach should be removed from the PCIA calculation.

Similarly, Humboldt is needed to serve its local area. In approving PG&E’s proposal to build Humboldt, the Commission stated: “The area is transmission-
constrained so that it cannot be fully supplied by any other plant.\textsuperscript{22} PG&E states that Humboldt is only operated when it is necessary for reliability or is "in the money". As with Pebbly Beach, there is no excess supply to serve this area, these costs were not incurred to serve departed load, there are no alternative facilities that could provide the needed generation at a lower price, and absent Commission regulation, PG&E could charge any price it wanted for Humboldt's output. PG&E includes Humboldt's $29.1 million annual costs in the PCIA calculation and appears to impute an estimated $30.9 million contribution to the PCIA benchmark value. As with Pebbly Beach, all uneconomic costs associated with Humboldt should be removed from PG&E's PCIA.

B. Correct the Methodology for Calculating Uneconomic Costs for Pumped-Hydroelectric Storage Facilities

PG&E's Helms\textsuperscript{23} and SCE's Eastwood pumped-hydroelectric storage facilities are included in the utilities' respective PCIA-eligible portfolios. The calculation of uneconomic costs for these facilities, however, requires modification. Helms and Eastwood are operated so that water is pumped uphill, typically during off peak periods when electricity costs for pumping are low.\textsuperscript{24} The water is released, and the units typically generate on peak when the electric generation is more valuable. Helms requires 1.5 kWh to pump enough water uphill to provide 1 kWh of generation. The ratio for Eastwood is better, at 1.33 kWh of pumping to 1 kWh of generation. However, both SCE and PG&E fail to reflect the lower cost of pumping

\textsuperscript{22} D.06-11-048 at 32.

\textsuperscript{23} The October 17, 2008 presentation on the operation of the Helms Pumped Storage Plant is attached as Exhibit 2B-A.

\textsuperscript{24} Conclusions regarding Helms rely on PG&E's response to ERRA 2018 PGE - Forecast _DR_CCSF_002-Q004-CONF, which is not attached. Conclusions regarding Eastwood are not based on actual data from SCE; the estimated pumping and generation is based roughly on the size of Eastwood compared to Helms.
compared to the value of the generation. The utilities’ PCIA calculations assume that
the price for electricity used to pump is the same as the price for the electricity
generated. This incorrect assumption makes the operation of Helms and Eastwood
appear uneconomic in the PCIA calculation, when in fact, it is not.

PG&E’s PCIA calculations contain another significant flaw in that PG&E, for PCIA
purposes, assumes that it takes over 3 kWh of pumping to provide 1 kWh of generation,
rather than the actual ratio of 1.5 to 1 kWh. Nor does PG&E account for the natural
water inflows to Helms that typically allow for 50 GWh or more generation annually with
no pumping requirements.

These incorrect assumptions regarding the Helms and Eastwood pumped
storage projects result in an overstatement of the uneconomic costs that are included in
PG&E’s and SCE’s PCIA calculations. Moreover, it should be noted that this does not
reflect the additional ancillary service, stability, renewable integration and storage
values of these facilities, whose inclusion would increase the applicable benchmark
values of these units and further reduce the level of uneconomic costs that are included
in PG&E’s and SCE’s PCIA calculations. Both of these types of errors should be
corrected.

C. Consider Whether Legacy Utility Owned Generation is Appropriately
Included in the PCIA-Eligible Portfolio

The existing PCIA calculation includes all costs of utility owned generation,
regardless of the date of commercial operation, but excluding generation managed
under the Cost Allocation Mechanism \(^{25}\) and “New World” generation that has been

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\(^{25}\) D.06-07-029.
operating for more than ten years. Including Legacy UOG pre-dating AB 117 in the PCIA, however, is at odds with the Legislature’s specific directives regarding CCAs and causes a cost shift from bundled to Departing Load customers.

As a preliminary matter, the Legislature anticipated in the mid-1990s that any above-market costs of the utilities’ Legacy UOG would be worked out of their portfolios by 2005. In addition, in the 2002 enactment of AB 117, the Legislature did not attribute cost responsibility for Legacy UOG – indeed, any UOG – to CCA customers. Finally, Legacy UOG costs have recently been removed from the PCIA paid by pre-2009 DA customers, and there is no reasonable basis for discriminating between those customers and other departing load customers with respect to recovery of Legacy UOG costs.

Despite these concerns, retaining the Legacy UOG in the PCIA-eligible portfolios could be found to be reasonable if the Commission adopts CalCCA’s proposals to: 1) attribute a premium value to GHG-free resources in this Chapter 2B, 2) securitize UOG assets in Chapter 3, and 3) provide CCAs and other bidders with access to GHG-free resources via an auction in Chapter 4. Departing load customers, particularly CCA customers who did not benefit from any past “below market” Legacy UOG costs offsetting “above market” portfolio costs, have contributed substantially to cost recovery for these resources. As detailed in Table 2B-1 below, the cost of PG&E’s Legacy UOG has been higher (on average 23% higher) than the corresponding PCIA Benchmark

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26 The Commission provided for allocation of cost responsibility to CCA and DA customers for “New World” utility-owned generation for a period of ten years from the date of Commercial operation. See D.03-12-039, D.04-12-048 and D.08-09-012.
Value since 2013, and these resources contributed an estimated $1.86 billion in uneconomic Legacy UOG costs during the past six years.

Table 2B-1

<table>
<thead>
<tr>
<th>PG&amp;E Legacy UOG Costs (Nuclear and Hydro) Historic Comparison to PCIA Benchmark Values</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
<th>Total/Average</th>
</tr>
</thead>
<tbody>
<tr>
<td>Brown Power Benchmark Value ($/MWh)</td>
<td>$38.90</td>
<td>$39.05</td>
<td>$41.25</td>
<td>$32.90</td>
<td>$35.22</td>
<td>$33.77</td>
<td></td>
</tr>
<tr>
<td>RA Benchmark Value ($/MWh)</td>
<td>$9.31</td>
<td>$11.03</td>
<td>$10.96</td>
<td>$12.63</td>
<td>$11.81</td>
<td>$11.16</td>
<td></td>
</tr>
<tr>
<td>Total PCIA Benchmark Value ($/MWh)</td>
<td>$48.21</td>
<td>$50.08</td>
<td>$52.21</td>
<td>$45.53</td>
<td>$47.03</td>
<td>$44.93</td>
<td>$48.00</td>
</tr>
<tr>
<td>Average Cost of Legacy UOG ($/MWh)</td>
<td>$51.52</td>
<td>$54.15</td>
<td>$55.90</td>
<td>$62.41</td>
<td>$66.81</td>
<td>$64.32</td>
<td>$59.19</td>
</tr>
<tr>
<td>Legacy UOG Cost as % of PCIA Benchmark Value</td>
<td>107%</td>
<td>108%</td>
<td>107%</td>
<td>137%</td>
<td>142%</td>
<td>143%</td>
<td>123%</td>
</tr>
<tr>
<td>Ununeconomic Legacy UOG Costs in PCIA ($ Millions)</td>
<td>$94</td>
<td>$110</td>
<td>$100</td>
<td>$454</td>
<td>$552</td>
<td>$545</td>
<td>$1,855</td>
</tr>
</tbody>
</table>

CalCCA is not proposing to remove Legacy UOG costs from the PCIA calculation as a part of its integrated proposal, given CalCCA’s proposals reduce their costs, revise their benchmark value and remarket their output as noted above and described further in subsequent chapters of this testimony. If, however, the Commission rejects the securitization of UOG costs, the integration of a GHG-free component to the benchmark and the proposal to make the GHG-free resources available to other LSEs, then the Legacy UOG costs should be removed from the PCIA-eligible portfolio.
EXHIBIT 2B-A
Helms Pumped Storage Plant
Northwest Wind Integration Forum Workshop

Manho Yeung
Pacific Gas and Electric Company
October 17, 2008
Pacific Gas and Electric Company - Overview

Headquarters Location
San Francisco, CA

Service Area
70,000 square miles in northern and central California

Service Area Population
15 million people (or about 1 of every 20 Americans)

Distribution Customer Accounts
5.1 million electric, 4.3 million gas

Employees
Approximately 20,000

System
- 159,364 miles of electric transmission and distribution lines
- 48,198 miles of natural gas T&D pipelines
- 6,271 megawatts of generation, including
  Diablo Canyon nuclear power plant,
  Helms pumped storage plant, and
  one of the largest hydroelectric systems in the country
**On average, More than 50% of PG&E’s Portfolio is Carbon-Free**

**PG&E’s 2007 Electric Delivery Mix**

- *These resources are climate neutral and/or renewable*
- Nuclear: 23%
- Large Hydro: 13%
- Renewable: 12%
  - Biomass and waste: 4%
  - Geothermal: 4%
  - Small hydroelectric: 2%
  - Wind: 2%
  - Solar: <1%
- Coal: 4%
- Natural Gas: 47%
- Other: 1%

**Note:** Delivery mix includes all of PG&E’s owned generation plus all of PG&E’s power purchases. PG&E’s direct purchases of coal have not increased and remain at 1.6%. The higher number on the chart is due to state regulations that assume a higher mix of coal in market purchases. Also, 2007 was a below normal hydro year.
Helms Pumped Storage Plant is in its 25th Operating Year

<table>
<thead>
<tr>
<th>Location</th>
<th>Central California, about 50 miles east of the City of Fresno</th>
</tr>
</thead>
<tbody>
<tr>
<td>Commission</td>
<td>June 30, 1984</td>
</tr>
<tr>
<td>Upper Reservoir</td>
<td>Courtright Lake 123,000 Acre Feet</td>
</tr>
<tr>
<td>Lower Reservoir</td>
<td>Lake Wishon 129,000 Acre Feet</td>
</tr>
<tr>
<td>Installed Capacity</td>
<td>Three units; 1,212 MW generating; 930 MW pumping</td>
</tr>
<tr>
<td>Average Energy</td>
<td>&lt;100 GWh per year (natural in-flow)</td>
</tr>
</tbody>
</table>

A-Courtright, B-Supply Tunnel, C-Turbine, D-Generator, E-Transformer, F-Wishon, G-Surge Chamber, H-Elevator
**Helms Generates During Day Time and Pumps at Night**

- Helms has three identical reversible pump-turbine motor-generator units
- 1,212 MW total in generation mode, and 930 MW total in pump mode
- Units are housed in a chamber about 1,000 feet underground
- In generating mode, water would
  - release from Courtright Lake
  - travel at 9,000 cubic feet per second
  - through a 22,000 feet long supply tunnel, and
  - drop 1,744 vertical feet before discharging into Lake Wishon
- In pumping mode, the units would reverse and pump water from Lake Wishon into storage at Courtright Lake
- Units have fast operating capability:
  - Dead stop to full generation in eight minutes
  - Dead stop to full pump in twenty minutes (single speed)
  - Generating ramp rate of 80 MW per minute per unit
**Helms Provides PG&E Customers with Many Benefits**

- Storage of **economy energy**, or surplus or lower cost energy that is sometimes available at night for daily cycling or during Spring runoff conditions for seasonal storage
- A large amount of **fast** acting spinning reserve and regulation capability, or generating capacity that is immediately available to meet fluctuations in electric demand
- Revenues from CAISO’s **energy and ancillary markets** (regulation, spin and non-spin)
- Helps alleviate **over-generation** or minimum load condition by using excess energy to pump water into storage
- Allows operation of **thermal** plants at a more steady output level, resulting in higher efficiencies
- Reduces dependence on fossil fuels and greenhouse gas emissions (**environmental benefits**)
Helms Operation – Typical Summer Week

Exhibit 2B-A-7
Helms’ Production Substantially Exceeds its Natural Inflow

Helms Pumped Storage Plant
Historical Annual Generation and Pumping

Year
2000 2001 2002 2003 2004 2005 2006 2007
Energy (GWh)
0 200 400 600 800 1,000 1,200 1,400 1,600
Generation
Energy Used for Pumping
Typical Range of Generation Prior to Formation of CAISO
Average Natural In-Flow
California Energy Crisis
Technical error in graph
Demand Increase has Consumed Transmission for Pumping

- Over the past 25 years, electric demand in central California has increased and has consumed some transmission capacity for pumping at Helms during off-peak hours.
- PG&E has plan to construct a new 150 mile long 500 kV transmission line to, among other things, restore Helms’ pumping flexibility.

*Illustrative Demand vs. Transmission Capability for Pumping*
Future Changes to Helms PSP Operation --- Unclear

Potential drivers are:

- Electric transmission constraints
- Intermittent renewable generation
- CAISO’s Market Redesign and Technology Upgrade initiative and its Nodal and Locational Marginal Pricing
- Western Electricity Coordination Council’s draft Frequency Response Reserve criteria in additional to the current spinning reserve requirement
PG&E is Evaluating New Pumped Storage Opportunities

- More pumped storage plants is good for power system operation
- In 2008, PG&E has sought and received FERC permits to evaluate potential pumped storage hydro facilities at Mokelumne River and Kings River
- PG&E is currently evaluating several potential pumped storage sites based on using a number of existing or new reservoirs
In Summary

- PG&E’s Helms Pumped Storage Plant has provided positive economic, reliability, operational and environmental values to PG&E’s customers for almost 25 years, with many more to come.
- Helms can facilitate storage of economy energy on both a daily and a seasonal basis.
- Helms is an effective means to resolve over-generation and minimum load issues.
- Helms, with its fast operating characteristics, is a valuable tool for system operators to meet changing demand and system conditions.
- Helms is very valuable in the ancillary market as well as the energy market.
- Helms can also be an effective tool to accommodate and integrate intermittent renewable resources.

QUESTIONS???