REBUTTAL TESTIMONY OF
THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION
ORDER INSTITUTING RULEMAKING TO REVIEW, REVISE, AND CONSIDER ALTERNATIVES TO THE POWER CHARGE INDIFFERENCE ADJUSTMENT  
R.17-06-026

REBUTTAL TESTIMONY OF  
THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION

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<td>Administrative and General</td>
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<td>AReM</td>
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<td>Direct Access</td>
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<tr>
<td>DACC</td>
<td>Direct Access Customer Coalition</td>
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<tr>
<td>DCPP</td>
<td>Diablo Canyon Power Plant</td>
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<tr>
<td>DOE</td>
<td>US Department of Energy</td>
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<tr>
<td>DR</td>
<td>Demand Response</td>
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<td>ERRA</td>
<td>Energy Resource Recovery Account</td>
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<tr>
<td>ESP</td>
<td>Electric Service Provider</td>
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<td>EUF</td>
<td>Energy Users Forum</td>
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<tr>
<td>FiT</td>
<td>Feed-in Tariff</td>
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<tr>
<td>GAM</td>
<td>Green Allocation Mechanism</td>
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<tr>
<td>GHG</td>
<td>Greenhouse Gas</td>
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<td>IOU</td>
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<td>IRP</td>
<td>Integrated Resource Plan</td>
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<td>LSE</td>
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<td>RFB</td>
<td>Request for Bids</td>
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<td>Request for Offer</td>
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<td>Regulatory Must-Run</td>
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<td>Renewables Portfolio Standard</td>
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<tr>
<td>SB</td>
<td>Senate Bill</td>
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<td>SCE</td>
<td>Southern California Edison Company</td>
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<td>SCP</td>
<td>Sonoma Clean Power</td>
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<td>San Diego Gas &amp; Electric Company</td>
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<td>San Onofre Nuclear Generating Station</td>
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<td>SPA</td>
<td>Staggered Portfolio Auction</td>
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<td>UOG</td>
<td>Utility Owned Generation</td>
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<td>URG</td>
<td>Utility Retained Generation</td>
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<td>VAAC</td>
<td>Voluntary Allocation &amp; Auction Clearinghouse</td>
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CHAPTER 1

INTRODUCTION

(Common Outline §I)
I. INTRODUCTION

CalCCA and the Joint Utilities appear to have started from a place of agreement in developing their proposals: It is challenging to identify reasonably representative, transparent values for all products and attributes in the utilities’ portfolios. The parties take this assessment, however, in two very different directions. The Joint Utilities ask the Commission to focus narrowly on the accounting exercise of allocating their “above market” portfolios among bundled and departing load customers. CalCCA, instead, asks the Commission to view this proceeding as an opportunity to exercise leadership in reducing portfolio costs and reforming the existing methodology to provide a transition to an integrated, durable solution for the changing retail market that would benefit all customers.

The Joint Utilities conclude that a cost shift is occurring from departing load to bundled customers and thus reject the current PCIA methodology. They propose to replace this methodology with the Portfolio Allocation Mechanism proposed in 2017, subject to limited modifications. Contemplating substantial and complex changes to the status-quo in the near term, the Joint Utilities’ proposal:

- Results in a cost shift from bundled to departing load customers.
- Abandons market valuation for certain RA and RPS attributes, substituting a mandatory, administrative allocation of these attributes to CCAs.
- Relies on prices from markets they believe “do not exist”\(^1\) and are not “functioning”\(^2\) to value other components of their portfolios.
- Constrains the ability of CCAs to meet the State’s climate goals in ways that best suit their local communities.

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\(^1\) Joint Utilities Direct Testimony, Chapter 3 at 5-9:1-23.
\(^2\) Id. at 2-7:3-5; App.B-22:11-12.
Focuses almost exclusively on how to slice the PCIA pie, ignoring the potential to reduce the size of the pie.

In contrast, CalCCA concludes that a cost shift is occurring from bundled to departing load customers, while acknowledging the sensitivity of this assessment to assumptions. In response, CalCCA takes a simple approach in the near term, with an eye toward broader reform in the long term to recognize the changing face of retail choice. We propose to:

- Retain the current PCIA benchmark methodology, reducing the potential for cost shifts by using a more reasonably representative value for capacity and recognizing the incremental value of GHG-free resources.
- Rely on the modified benchmark as a bridge to the development of a more liquid market for utility resources, which can provide a transparent and reliable market price benchmark.
- Enable CCAs, through enhancement of markets for utility RPS and GHG-free resources, to meet State climate goals in ways that best serve their local communities.
- Reduce the size of the PCIA pie, offering recommendations such as securitization to reduce costs for all customers, rather than focus narrowly on slicing the pie.

The Commission must determine which of these proposals best positions California for the future. Commission Staff has estimated that the Joint Utilities could lose as much as 85% of their native load to other suppliers by the mid-2020s. With this end state in mind, several high-level observations help to bring the solution into sharper focus. First, abandoning the goal of well-functioning RA and RPS markets is anathema to the continuing growth in market participants and service options. The Commission, instead, should make every effort to enable liquid markets both to relieve the utilities’ supply and load imbalance and to enhance the availability of transparent market prices.

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3 See CPUC Staff White Paper: Consumer and Retail Choice, the Role of the Utility, and an Evolving Regulatory Framework, at 3.
Second, allowing the Joint Utilities to control the majority of resources needed to serve their service territories, while serving only 15% of the load, creates an untenable balance for the utilities and their customers and could ultimately raise questions of market power. The Commission’s goal should be to rebalance utility supply and demand magnitude. Third, limiting the CCA’s abilities to make independent procurement choices hampers their ability to fulfill the State’s climate goals in ways that are most effective for their communities. Solutions that enhance that flexibility best serve State policy goals. Finally, on the path to rebalancing utility supply and demand and fostering transparent market prices, the Commission should minimize disruption and avoid using values in the PCIA calculation that do not reasonably capture the value of the utilities’ portfolios. CalCCA’s integrated, comprehensive proposal best serves this vision as a reasonable transition to California’s future electricity market.

II. THE JOINT UTILITIES’ EFFORTS TO CAST THE PCIA AS A QUESTION OF ECONOMIC JUSTICE IS MISLEADING

The Joint Utilities claim that “the cost shift that has occurred to date under the Current Methodology has been disproportionately borne by bundled service customers in communities below the State-wide mean income level.” As an initial matter, CalCCA disagrees that costs have been shifted to bundled customers as explained in our direct testimony. In addition, the Joint Utilities’ attempt to paint a picture of economic inequality between bundled and departing load customers fails to tell the whole story. Instead of correcting the alleged inequality, the Joint Utilities’ proposal would only serve to further hinder the efforts of CCAs to reach lower-income areas and expand the benefits of local control over energy procurement.

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4 Joint Utilities Direct Testimony at 1-18.
5 See generally CalCCA Testimony Chapter 2A.
CCAs are currently operating, or are in the advance stages of planning, for launch in 18 counties, with a total population of over 20,000,000 residents. Assertions that CCAs predominantly serve higher income, coastal communities are misplaced. Based on an analysis of the CalEnviroScreen 3.0 screening tool,\(^6\) 19% of residents in CCA Counties (i.e. counties where a CCA is currently serving or planning to serve 25% or more of the population) live in census tracts ranked in the top 25% for poverty statewide. An additional analysis of CCA customers on CARE rates, shown in Exhibit 1-A indicates that (among the CCAs that reported results) CCAs have on average 22% CARE customers, equivalent to the roughly 20% of utility customers on CARE rates. This high-level assessment of both poverty levels and CARE participation in CCA communities demonstrates that CCAs serve communities struggling with the same poverty challenges as the State of California at large and the communities in the Joint Utilities’ service territories. CCAs are making strides to address the low-income community as described in CalCCA’s *Environmental Justice & Social Equity* publication, attached as Exhibit 1-B.

Economic justice is not only a function of how the Commission allocates portfolio costs; equally or more important is reducing the size of the problem. The Commission should observe that while claiming to champion low income customers, the Joint Utilities have failed to propose ways to reduce the overall level of PCIA costs. CalCCA’s proposal for contract buydown, securitization of assets and improved portfolio management are aimed to benefit all customers, regardless of their income levels.

\(^6\) CalEnviroScreen 3.0: Poverty scores and rankings for 18 CCA counties for total population and population living in census tracts ranked in the top 25% of the State for poverty.
Exhibit 1-A

Percentage CARE Customers Served by Existing CCAs and Anticipated to be Served by Launching CCAs

<table>
<thead>
<tr>
<th>CCA</th>
<th>County(s)</th>
<th>Total Residential Customer Accounts Served</th>
<th>Total CARE Customer Accounts Served</th>
<th>% CARE Customers Served</th>
</tr>
</thead>
<tbody>
<tr>
<td>CPA</td>
<td>Los Angeles, Ventura</td>
<td>639,675</td>
<td>278,724</td>
<td>44%</td>
</tr>
<tr>
<td>CPSF</td>
<td>San Francisco</td>
<td>335,876</td>
<td>40,713</td>
<td>12%</td>
</tr>
<tr>
<td>EBCE</td>
<td>Alameda County</td>
<td>569,000</td>
<td>103,000</td>
<td>18%</td>
</tr>
<tr>
<td>LCE</td>
<td>Los Angeles</td>
<td>45,607</td>
<td>18,304</td>
<td>40%</td>
</tr>
<tr>
<td>MCE</td>
<td>Marin, Napa, Contra Costa</td>
<td>415,033</td>
<td>68,124</td>
<td>16%</td>
</tr>
<tr>
<td>PCE</td>
<td>San Mateo</td>
<td>262,678</td>
<td>30,285</td>
<td>12%</td>
</tr>
<tr>
<td>PRIME</td>
<td></td>
<td>15,588</td>
<td>6,470</td>
<td>42%</td>
</tr>
<tr>
<td>RCEA</td>
<td>Humboldt</td>
<td>52,600</td>
<td>14,900</td>
<td>28%</td>
</tr>
<tr>
<td>SCP</td>
<td>Sonoma, Mendocino</td>
<td>190,438</td>
<td>35,207</td>
<td>18%</td>
</tr>
<tr>
<td>SVCP</td>
<td>Santa Clara</td>
<td>248,085</td>
<td>23,515</td>
<td>9%</td>
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</table>

Total   | 2,774,580        | 619,242                                    | 22%                               |
As local government agencies, CCAs strive to promote diversity and inclusion. By harnessing the dynamic power of community, we empower customers to make better choices for their households, for the climate, and for our collective future. We seek to ensure the diversity of our communities is included in our service offerings and programs, workforces and supply chains. Doing so invests back into our customer base and drives sustainable futures.

CCAs have launched a wide range of programs and initiatives to increase equity and support disadvantaged community members.

**Local Control: Accessible, Accountable & Transparent Governance**

CCA Boards, governed by locally elected officials, set policy for:
- Procurement
- Rates
- Projects and Programs
- Workforce Development
- Community Benefits

Board meetings are open to the public, subject to the Brown Act, and held in the communities they serve, inviting direct participation and observation in decision-making. By contrast, average customers do not have access to CPUC Commissioners, who are appointed, in the way they have access to CCA governing boards, who they elect and are located in their community. Customers also do not have access to IOU executives or IOU board members, as their primary legal obligation is to their shareholders.

### Making Rooftop Solar Accessible

- **$2 Million** allocated by CleanPowerSF for solar rebates for underserved residential customers through GoSolarSF. Low-income homeowners can save up to 100% off the installed cost of solar.
- **$345,000** allocated by MCE for low-income solar rebates. Estimates indicate rebate-assisted installations have saved customers $2+ Million on their electricity bills.
- **Lancaster Choice Energy** focuses on low-income customers with California HERO and California first to offer Property Assessed Clean Energy (PACE) financing.

(Continues on next page)
**Environmental Justice & Social Equity**

**Energy Efficiency for Home Comfort, Health & Savings**

- $1.7 Million allocated annually through MCE's Low-Income Tenants & Families program for $1,200 per unit rebate and free electric heat pump. Participants must be at or below 200% Federal Poverty Guidelines.
- Sonoma Clean Power is expanding access to home energy audits with free do-it-yourself toolkit in all public libraries.
- $408,000 in energy efficiency rebates distributed by MCE to 760 affordable multifamily units.

**Local Job Training & Employment**

CCAs are committed to creating partnerships with and financially supporting organizations that provide workforce development opportunities, including training, apprenticeship and per-apprenticeship programs in diverse communities.

- $470,812 contributed to local green workforce job training and employment programs by MCE.
  - 1,797 hours of on the job training, Marin City Community Development Corporation
  - 330+ hours of construction skills training, numeracy and literacy training, job placement, case management, job-site mentoring and employment counseling, RichmondBUILD
- Trained youth provided no-cost energy and water assessments and installations to Richmond, San Pablo and El Cerrito residents through MCE's Multifamily Energy Savings Program, Rising Sun Energy Center
- Local solar install training, focusing on under-served communities, GRID Alternatives

**Access to Electric Vehicle Programs**

- Sonoma Clean Power provides electric vehicle purchase assistance and lease discounts for CARE customers; 30% of electric vehicle rebates are allocated for low-income customers.
- Lancaster Choice Energy is partnering with Atelope Valley Transit Authority, which provides free transit to seniors, to convert to all-electric bus fleet within three years.

**GRID ALTERNATIVES**

GRID Alternatives is a nonprofit that manages the country's first dedicated solar rebate for low-income families. They provide no-cost solar systems for low-income families, while providing hands-on installation experience for job seekers and community volunteers.

**ECO2SCHOOLS**

Eco2Schools Program is led by Center for Climate Protection inspires students in two high schools and a youth organization in Hunters Point to be more sustainable and reduce carbon footprints, with assistance from CleanPowerSF.

**COMMUNITY POWER COALITION**

MCE's Community Power Coalition of ratepayer advocates and community-based organizations focuses on the interests of underrepresented and historically marginalized constituencies. Partners include Communities for a Better Environment, the Greenlining Institute, Grid Alternatives, the Sierra Club and local community environmental justice organizations.
CALIFORNIA COMMUNITY CHOICE ASSOCIATION
REBUTTAL TESTIMONY

CHAPTER 2A

PCIA EFFECTIVENESS IN AVOIDING COST SHIFTS
(Common Outline §II.A)
I. THE JOINT UTILITIES’ METHODOLOGY FOR DETERMINING WHETHER A COST SHIFT IS OCCURRING IS IRREPARABLY FLAWED

A. The Joint Utilities’ Characterization of “Net” Avoidable Costs Fails to Capture the Full Value of their Portfolios

The Joint Utilities and CalCCA agree that the current PCIA results in a cost shift, but differ materially on the direction of that shift. The Joint Utilities contend that the “PCIA is no longer able to ensure that bundled service customers are financially indifferent to departing load….”7 They believe that the amount of the cost shift can be calculated with precision using an algebraic proof.8 CalCCA reaches the opposite conclusion, that bundled customers currently are imposing a significant cost shift on departing load customers.”9 While confident on the general direction of the cost shift and the principles that drive the result, CalCCA does not agree that a precise assessment can be made under current conditions in the California electricity market.10 In these circumstances, the Commission must exercise its experience with administrative benchmarks to develop the best assessment of cost shift potential, applying reasonable judgment to available data.

Determining whether a cost shift is occurring between bundled and CCA departing load customers requires an assessment of the “net unavoidable costs” of the utility portfolio and “attribution” of those costs to each customer. “Net unavoidable costs,” which we refer to as Net Costs, are portfolio costs, net of benefits or value, that cannot be avoided through prudent utility procurement and portfolio management. “Attribution” of these costs requires consideration of whether the costs were incurred on

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7 Joint Utilities Direct Testimony at 1-2:11-13.
8 See id. at 2-22:18-22.
9 CalCCA Testimony at 2-14.
10 Id. at 2-10:16-21.
behalf of a customer. If each customer bears cost responsibility for the net unavoidable portfolio costs attributable to that customer, no cost shift occurs. To the extent a customer bears more (or less) than this amount, a cost shift to (or from) that customer has occurred.

The Joint Utilities’ cost-shift assessment is driven by a fundamentally different definition of “net” portfolio costs. CalCCA’s approach defines “net” avoidable costs as actual portfolio costs less portfolio value, acknowledging the challenges of determining the “value” of an integrated, long-term portfolio, CalCCA uses reasonable administrative proxies together with actual short-term brown power prices to measure value. This approach is consistent with §366.2(g), which provides:

Estimated net unavoidable electricity costs paid by the customers of a community choice aggregator shall be reduced by the value of any benefits that remain with bundled service customers….¹¹

The Joint Utilities, in contrast, define “net” unavoidable costs comparing portfolio costs with only the revenues the utility could generate today in non-transparent, limited markets for a limited subset of products and attributes. This narrow approach fails to adequately value the benefits of products and attributes remaining in the portfolio for bundled service customers.

The Joint Utilities suggest a need for absolute precision in the use of actual market prices for determining cost recovery. They state that “the Current Methodology results in indifference if, and only if, the MPB is equal to the actual prices that can be obtained in the market from selling the departing load customers’ share of the generation portfolio.”¹² This statement is akin to stating that rates paid by a utility’s

¹² Joint Utilities Direct Testimony at 2-3.
customers are reasonable if, and only if, the utility’s actual expenditures during a rate period precisely equal the expenditures it forecast in the relevant rate case. For the many costs outside of balancing accounts, however, precision is not a prerequisite to cost recovery or earnings (although that could be arranged). Similarly, the assertion is equivalent to saying that utility ratepayers should pay the prudently incurred costs of commitments taken on their behalf, if, and only if, the costs and benefits of those commitments turn out to be exactly equal to the projections used to determine the cost-effectiveness of that commitment. Determining appropriate cost responsibility requires the use of a reasonably representative value for the benefits of the portfolio assets.

This includes a full assessment of the array of attributes that remain with bundled customers.

B. The Joint Utilities’ Methodology for Analyzing Cost Shifts Lacks Credibility

The Joint Utilities’ position lacks credibility in a number of substantive ways. First, they contend that a capacity market “does not exist” that would provide revenues to compensate for the “full capacity value” of their resources and observe the “lack of a functioning and transparent capacity market.” Despite their clear dismissal of capacity markets, they rely on short-term RA market prices to conclude that the current PCIA methodology “results in cost shifts to remaining bundled customers.” There is no discernible logic support that the alleged “prices” from a “market” the Joint Utilities conclude is dysfunctional provides a better assessment of capacity value than either the current benchmark or the enhancement proposed by CalCCA.

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13 Joint Utilities Direct Testimony at 5-9:20-23.
14 Id. at 2-7:3-6.
15 Id. at 2-20:13-14.
Second, the Joint Utilities reject administratively set benchmarks as reasonable proxies because, by definition, they "rely on incomplete information about markets and thus can deviate substantially from actual market outcomes."\(^{16}\) The Joint Utilities would, instead, prefer to rely on prices from a dysfunctional market that “does not exist” or capture the “full value” of the resources. This perspective on administratively set benchmarks delegitimizes the planning exercises the Commission undertakes and fails to recognize the reasons why such benchmarks have been developed and used. Not all market activity occurs in transparent public transactions, with the most significant transactions hidden behind confidentiality protections for at least three years.

Moreover, short-term market prices cannot value long-term resources, and these markets do not capture all of the dimensions of value (e.g., hedge value) embedded in a resource. There may also be attributes (e.g., GHG-free value) that have value but for which there is no clear, transparent market. Administratively set benchmarks attempt to identify and reasonably value these and other benefits that cannot be readily identified in a transparent price. If the Commission truly believed that the full value of the Joint Utilities' long-term resources is captured by a limited subset of short-term market prices, it would have been satisfied to continue to allow the utilities to buy in the spot market as they did in the early years of electric industry restructuring.

Third, the Joint Utilities’ contention that a cost shift exists assumes that the prices available in the market today, through the market mechanisms they advocate, are the maximum that could be obtained if a utility liquidated the departing customer’s portfolio share. To our knowledge, none of the utilities has ever undertaken a full auction, nor have they actively participated in CCA procurement processes, to sell the full bundle of

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\(^{16}\) Id. at 2-10.
attributes associated with a departing customer’s share. We recognize that prudent
management may require retaining certain of these resources to maintain the resources
in the interest of bundled customers to mitigate price risk or bank RECs for future
renewable portfolio standard requirements. In such a case, however, the cost of the
resources should not be attributed to departing load customers.

Fourth, the Joint Utilities’ cost shift analysis assumes that energy, System RA
and RECs are the only products or attributes with value in the utilities’ portfolios. As
demonstrated in CalCCA’s opening testimony, the portfolio contains more products,
including the value of GHG-free supply. Energy Users Forum perhaps said it best,
oberving that the current method “undervalues utility assets, ignores the value of
optionality (hedge value), and does not price all components of contract value and
results in lost value…” The Joint Utilities do not reflect all the monetized values of
their generating facilities, failing to consider millions of dollars of Other Operating
Revenues shown in the Joint Utilities’ general rate cases.

Fifth, the Joint Utilities’ cost shift contention implicitly assumes that 100% of the
costs in the existing portfolio are “unavoidable,” that there is nothing further that could
be done to reduce the PCIA level and, consequently, an alleged cost shift. As CalCCA
proposed in its opening testimony, securitization of rate base and/or PPA buydown
transactions and improved portfolio management carry the potential to substantially
reduce portfolio costs. Prudence is not only about procurements; the utilities have a
duty to carefully manage and mitigate procurement costs for the benefit of all
customers, including departing load customers.

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17 CalCCA Testimony at 2B-10 – 2B-11.
18 Energy Users Forum Direct Testimony at 4.
19 See generally CalCCA Testimony, Chapter 3.
Sixth, it has been argued that in theory it is reasonable to value the utilities’ physical resources at spot market prices because spot market prices represent a good proxy for long run replacements costs, but in practice CAISO spot prices never rise to a level that approximates the utility’s costs of acquiring new resources. If spot prices are chronically suppressed to a level that is too low to cover the costs of new entry, then there must be a different revenue or value stream beyond spot prices that must be paid in order to maintain a sustainable market in equilibrium. CalCCA believes that this is the case in the California market — spot market prices do not adequately capture the long-term value of resources and therefore another benchmark is needed to provide a meaningful indicator of the value of long-term physical resources. The history of CAISO short-term auction prices – the basis for the forward brown power price benchmark – shows that no new resources would have been built based on these values since at least 2002. Since 2002, the CAISO has published its Annual Report on Market Performance & Issues which includes an assessment of the projected costs for constructing new combined cycle generating turbines and combustion turbines and the realized net revenues after operating expenses for those types of resources in the CAISO auction markets.\textsuperscript{20} If the theory were to hold based on actual historical experience in the California market, those market net revenues would reliably need to be sufficient on average to recover the investments in new generation. Instead, the CAISO reports show the net revenues have never been sufficient to cover these installed costs. Since 2007 when the CAISO updated its installed costs for more accurate data, the average shortfalls for a new CT have been $150/kW-yr in the NP15

zone and $140/kW-yr in SP15. In other words, the shortfalls have been larger than the
administratively set capacity benchmarks that CalCCA advocates to be used for valuing
the utilities’ portfolio. If such large discontinuities are occurring in a market, most likely
that market has significant market failures that must be adjusted for, and spot market
prices cannot be used when selecting a reasonably representative market value.

Necessary, reasonable and implementable adjustments have been identified in
CalCCA’s testimony, which can improve many of the deficiencies in the current
valuation methodology.

CalCCA appreciates the desire of the Joint Utilities to find simplicity and precision
in analyzing portfolio value and cost shifts. Their approach, however, is deceptively
simple and ignores the complexities of California’s market structure and procurement
planning processes. Fortunately, the Commission is no stranger to the more
challenging and nuanced analysis required to address the issues in this proceeding.

II. TURN’S FRAMEWORK FOR ANALYZING COST SHIFTS MUST BE SET IN A
BROADER CONTEXT OF “COST SHIFT” DEFINITIONS

TURN’s approach to evaluating cost shifts mirrors the Joint Utilities’ approach
and thus suffers the same shortcomings. In addition, TURN’s seeming reliance on a
very narrow interpretation of SB 350’s prohibition on cost shifts must be set in context.

TURN, like the Joint Utilities, argues that to achieve “true indifference” requires
comparison of the portfolio’s “actual gross costs less their realized market benefits.”\(^{21}\)

TURN, however, misses a critical point. “Realized” market benefits cannot tell the full
story; realized benefits – assuming prudent portfolio management – provide only a
measurement of the revenues from what was sold in the market. “Realized” benefits do

\(^{21}\) TURN Direct Testimony at 5 (emphasis supplied).
not provide an accurate valuation for resources left in the portfolio to retain other
attributes of value for bundled customers. Realized benefits could not provide an
accurate measure unless all portfolio resources were bought and sold in the market
(which would call into question the prudency of such a fire sale). In addition, not all
attributes are sold in the short-run market, but are instead realized in long-term
transactions between the utilities and ratepayers, e.g., hedging benefits. Using short-
term transactions nullifies the hedge value by definition. For the same reasons
discussed in Section I, above, TURN’s effort to oversimplify the assessment of portfolio
value is flawed. Finally, TURN’s analysis assumes prudent portfolio management – an
assumption that must be closely examined.

TURN also observes that SB 350 requires that “bundled customers shall ’not
experience any cost increases due to customers leaving bundled direct access [sic] for
Direct Access (DA) service by ESPs or the creation of CCAs.”22 TURN goes on to
argue:

The word “cost” suggests that the Legislature intended the above-cited
code sections [in SB 350] to address the allocation between bundled and
unbundled customers of those costs that are recovered in rates. As a
corollary, these code sections suggest that the Commission should not
consider other theoretical or potential values of IOU resources that are not
reflected in the IOUs’ rates.23

CalCCA agrees that “theoretical or potential value of IOU resources that are not
reflected in IOUs’ rates” cannot themselves be allocated to departing load. Importantly,
however, the statute does not prevent the use of theoretical or potential values to

assess the portfolio value or to allocate portfolio costs to rates.

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22 Id., at 3.
23 Id.
In addition, any use of the “cost increases” language from SB 350 must be set carefully in context. Carrying TURN’s focus on “cost increases” too far – preventing any increases to bundled customers – would lead to an absurd result. Under this interpretation, the Commission could not adopt a solution in this case that increases bundled customer costs, even if the increase were due to corrections required to reverse existing cost shifts from bundled to departing load customers. Thus, the “cost increase” language of SB 350 must be viewed in a broader context and harmonized with other expressions of the prohibition on “cost shifts,” including AB 117’s more specific delineation of departing customer cost responsibility.24

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24 See CalCCA Testimony, Chapter 2, § I.
CALIFORNIA COMMUNITY CHOICE ASSOCIATION
REBUTTAL TESTIMONY

CHAPTER 2B

REVISING THE CURRENT PCIA METHODOLOGY
(Common Outline §II.B)
CalCCA proposes to retain the current PCIA methodology with an aim toward broader reform. In retaining this methodology, however, it is necessary to modify the market price benchmarks to better reflect portfolio value and thereby prevent cost shifts. CalCCA’s proposed modifications address both the scope of products and attributes recognized by PCIA value measures and the source of those measures.

The Energy Users Forum best articulated the problem with the scope of value measures in the current PCIA benchmark. It stated “the current method undervalues utility assets, ignores the value of optionality (hedge value), does not price all components of contract value and results in lost value….”25 In this vein, CalCCA proposes broadening the scope of the benchmark to value more of the products and attributes held in the utility portfolio. While the proposal does not explicitly reach to all components of value (e.g., hedge value), it focuses particularly on valuation of the GHG-free attribute, for hydroelectric and nuclear assets, and ancillary services.

Additionally, CalCCA also proposes adoption of a capacity price benchmark that more reasonably represents the value of capacity, particularly the longer term value; the modified benchmark implicitly broadens the recognition of capacity value beyond simply System RA.

The Joint Utilities oppose retention of the current PCIA methodology eliminating the use of any benchmark through the GAM and PMM. CalCCA responds to parties’ views on existing benchmark values, including capacity, ancillary services and the Green Adder. It further highlights the implicit support for a GHG-free adder evident in parties’ testimony and the utilities’ choice to continue to operate certain UOG assets.

25 EUF Direct Testimony at 4.
I. THE CURRENT PCIA BENCHMARK UNDERSTATE CAPACITY VALUE FOR PCIA-ELIGIBLE RESOURCES

A. The Prices Captured by the 2016 Resource Adequacy Report Do Not Reasonably Represent the Value of All Capacity in the Joint Utilities’ Portfolios

The Joint Utilities, supported by TURN and ORA, contend that the current PCIA benchmark overstates capacity value and causes a cost shift.\(^{26}\) They estimate a cost shift of $21/kW-yr for 2018; this represents the difference between the current PCIA benchmark value of $58/kW-yr and $37/kW-yr, which they assert is the weighted average price of RA capacity from the Commission’s 2016 Resource Adequacy Report. They reason that the capacity price is overstated because “RA capacity can generally be procured at prices much lower than the administratively-set benchmark price … and excess RA cannot be monetized at prices approaching the benchmark price.”\(^{27}\) They further note that the price is the result of excess capacity in the market.

The Joint Utilities’ view, as observed in Chapter 2A, lacks credibility and is internally inconsistent. While relying on short-term RA market prices to “prove” a cost shift, they also maintain that “the state has not developed a capacity market.”\(^{28}\) Further, they argue that a capacity market “does not exist that would provide additional revenues to compensate for the full value of post-2002 resources.”\(^{29}\) The logical conclusion from these statements is that the short-term RA market does not “compensate for the full value of post-2002 resources” that are retained in the portfolio for bundled customers.

CalCCA agrees and, for this reason, has looked to other estimates of value for capacity held in the utilities’ portfolios, adopting a shorter term, public and then transparent value

\(^{26}\) Joint Utilities Direct Testimony, Figure 2-1.
\(^{27}\) Id. at 2-14:4-7.
\(^{28}\) Id. at 5-9:20-21.
\(^{29}\) Id. at 5-9:21-23 (emphasis supplied).
for products sold into the market and a longer term, administratively determined value for resources remaining in the portfolio.

TURN sings the same tune as the Joint Utilities, arguing that the current RA benchmark “has very little relationship to the actual market prices at which all LSEs buy and sell RA capacity.” In arguing that a cost shift is occurring, TURN relies on the same comparison advanced by the utilities, based on the Commission’s 2016 RA Report.\(^\text{30}\)

TURN, like the Joint Utilities, ignores the optimality value of holding long-term capacity retained in the portfolio for bundled customers.

The Joint Utilities, TURN and the 2016 RA Report all ignore the market distortion that stems from the hybrid market; less than 20% of the RA capacity used to meet compliance obligations is actually priced through the very limited set of bilateral contracts underlying the 2016 RA Report. Net Qualifying Capacity used for RA compliance comes in several distinct product forms, including System RA, Local RA and Flexible RA, obtained by LSEs from: (1) bilateral contracting, (2) the CAM, (3) the CAISO Capacity Procurement Mechanism and (4) CAISO Regulatory Must-Run contracts. The 2016 RA Report, however, reflects prices for only a limited set of bilaterally contracted Local and System RA products. The 2016 RA Report’s price analysis ignores the majority of capacity that is procured via long-term PPAs rather than via short-term transactions, overlooks capacity obtained from PCIA-eligible resources, and makes no attempt to assign any value to the capacity of UOG resources held in the portfolio. Moreover, the 2016 RA Report discloses prices for only one-year products and it masks data for 2018-2020 transactions,\(^\text{31}\) representing prices for the latter period

\(^{30}\) TURN Direct Testimony at 6-7.

\(^{31}\) Id.
with 2016 and 2017 prices. All long-term transactions – which should be the focus of valuation for existing physical resources – are explicitly excluded from the 2016 RA Report. This simple fact renders the report of marginal use in valuing the majority of the capacity in the utilities’ portfolios.

Relying on the 2016 RA Report, the contracted volumes represented only 19.7% of the RA Requirement for 2016, 14.9% for 2017 and 10.6% for 2018-2020. Bilaterally contracted RA capacity provides a very limited view of the overall capacity “market” and represents primarily the short-term residual transactions that LSEs engage in to balance their positions. There is no reasonable basis for using the narrowly circumscribed average prices provided in the 2016 RA Report to make sweeping generalities about the overall value of capacity in the California market or the Joint Utilities’ portfolios.

Moreover, the quantity of capacity reported to have been acquired through bilateral contracts in the 2016 RA Report is approximately equal to the quantity of capacity that is allocated to LSEs – including from DR, CAM and RMR. Capacity from these sources represented 20% of the LSEs’ RA compliance requirement for 2016. Unlike the short-term bilateral contracts, however, the 2016 RA Report makes no effort to explore the value of these resources.

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32 Id. at 23.
33 CalCCA derived these percentages from Tables 3, 4 and 6 of the 2016 RA Report. For 2016, this percentage is calculated by dividing: a) the 2016 Contracted Capacity of 90,341 Monthly MW in Table 6, by b) the 2016 RA Requirement of 458,019 Monthly MW obtained by summing the 12 monthly values on the first line of Table 4. (90,341)/(458,019) = 19.7%. Similar calculations were done for 2017 and 2018-2020 under the illustrative assumption that RA requirements remained constant at the 2016 level.
34 CalCCA derived this estimate using Table 4 of the 2016 RA Report. For 2016, this percentage is calculated by dividing: a) the 2016 DR/CAM/RMR Capacity of 91,552 Monthly MW obtained by summing the 12 monthly values on the “DR plus 15% PRM” and the “CAM & RMR” lines of Table 4, by b) the 2016 RA Requirement of 458,019 Monthly MW obtained by summing the 12 monthly values on the first line of Table 4. (91,552)/(458,019) = 20.0%.
Since LSEs serving departing load are paying the full cost of the DR, CAM and RMR resources, their cost is at least a meaningful indication of the “price” the IOUs are receiving for capacity as the reported prices in the 2016 RA Report. It follows that it would be at least as meaningful to use the average costs of those DR/CAM/RMR resources to estimate the value of capacity as it would be to use the prices reported in Table 6. Calculating an implied capacity value based solely on CAM resources and doing a weighted average of this capacity value with the results of the 2016 RA Report, would produce a capacity “price” for these long-term and short-term resources of $124/kW-yr.\(^{35}\) This value is higher than CalCCA’s proposed capacity benchmark value for long-term resources ($110.93/kW-yr and $102.31/kW-yr for PG&E and SCE, respectively), and far exceeds the $75.72/kW-yr CPM capacity benchmark value proposed by CalCCA for short-term resources. The $124 kW-yr value also comes close to the shortfall between the cost of building a new resource and CASIO revenues, as discussed in Chapter 2A.

Finally, even putting these resources together with the short-term bilaterally contracted resources does not give a reasonable view of value, since the 2016 RA Report excludes capacity from PCIA resources.

**B. UOG Operating Data Suggest the Current PCIA Benchmark Understates Capacity Value**

A higher value for capacity from PCIA-eligible resources is revealed through a comparison of those resources’ operating costs with the current PCIA benchmark. PG&E continues to operate its fossil facilities (Gateway, Colusa and Humboldt), and its nuclear facility (Diablo Canyon), despite those facilities having avoidable, incremental

\(^{35}\) See CONFIDENTIAL Exhibit 2B-A.
costs of operation that are significantly above the current combined PCIA benchmark for energy and capacity.\(^{36}\) Based on the 2018 ERRA cost forecast and PCIA benchmark value, PG&E’s fossil plants are not cost-effective to operate in 2018. Diablo Canyon operating costs are forecast to be $878 million compared with a PCIA benchmark value of $728 million (energy and capacity), for net uneconomic operating costs of $150 million. Likewise, PG&E’s fossil generation fleet is forecast to have a variable operating cost of $334 million compared with a benchmark value of $286 million, leaving $48 million of uneconomic operating costs.

<table>
<thead>
<tr>
<th>Generating Station</th>
<th>MW NQC</th>
<th>Variable Operating Cost ($million)</th>
<th>PCIA Benchmark Value ($million)</th>
<th>Uneconomic Operating Costs ($million)</th>
<th>$/kW-yr Operating Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>PG&amp;E Diablo Canyon</td>
<td>2280</td>
<td>$878</td>
<td>$728</td>
<td>$150</td>
<td>$116</td>
</tr>
<tr>
<td>PG&amp;E Fossil</td>
<td>1366</td>
<td>$334</td>
<td>$286</td>
<td>$48</td>
<td>$85</td>
</tr>
</tbody>
</table>

One of two conclusions can be drawn: either these facilities are not economic to operate, in which case they should not be operated, or the benchmark does not fully reflect their value.

CalCCA believes the latter is the more likely explanation. To make the fossil generation economic requires an assumption of a capacity value of at least $85/kW-yr, as compared to the current PCIA benchmark value of $58/kW-yr. In other words, PG&E is paying itself a capacity value of $85 kW-yr for its fossil plants (excluding the substantial profits PG&E earns on its fossil investment), but only crediting CCA

\(^{36}\) Avoidable costs exclude all costs associated with existing sunk costs (depreciation, income taxes and return on rate base), and include only costs of continuing operation (fuel, O&M, A&G, new capital additions).
customers for $58/kW-yr. This is a readily discernible cost shift of at least $27/kW-yr from bundled to CCA customers.

Diablo Canyon is even more expensive to continue to operate. Based on PG&E's 2018 forecasts, Diablo Canyon is not cost effective to operate, even with the higher $85/kW-yr capacity value. To justify continuing to operate Diablo Canyon, there must be additional value assumed for its generation, such as an even higher RA value of $116/kW-yr or an adder reflecting its GHG-free generation. Combined with an $85/kW-yr capacity value, a GHG-free adder of $4/MWh is needed to justify PG&E's decision to continue operating Diablo Canyon.

PG&E's fossil plants and Diablo Canyon account for over 3600 MW of PG&E's NQC, more than 25% of its total resources, and all of PG&E's supposed excess capacity. The fact that an $85/kW-yr capacity value at minimum is necessary to justify their operation demonstrates that the current PCIA benchmark value for capacity is too low, and the purported "market" capacity values presented in the 2016 RA Report do not reflect the actual value of these resources. If higher values for capacity and for GHG-free generation are not factored into the PCIA benchmark, operation of these facilities is uneconomic and results in "avoidable" costs that should not be included in the PCIA calculation. CalCCA agrees with the Joint Utilities that California's short-term capacity market does not compensate for "the full value" of long-term resources.

Similarly, SCE's 2018 forecasts of the avoidable costs of operating Palo Verde are above SCE's proposed energy and RA. In addition, SCE's 2018 ERRA forecast of the fuel and direct GHG costs of its Mountainview facility also demonstrate that PCIA

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37 See PG&E 2018 ERRA Testimony, Table 3-1. It should be noted that the operation of these facilities results in significant amounts of excess capacity in PG&E's portfolio, and thereby drives down the "market" price for RA, potentially resulting in further increases in the PCIA.
assumptions understate the value of energy. SCE’s forecast of the fuel and direct GHG costs of dispatching Mountainview are more than $20 million higher than the average MPB value of brown energy, and over $12 million more than the on-peak PCIA brown energy value. Mountainview is not needed for reliability, so it should only be producing energy when it is below the market price for energy. Yet SCE’s 2018 ERRA forecasts indicate that Mountainview is operated more than 35% of the hours in the year when it is not cost-effective to do so, incurring higher costs for bundled customers.

Once again, there are only two conclusions that can be drawn from these facts. Either there is value – in excess of the PCIA benchmark – to retaining the resources in the utility’s portfolio or the facilities are uneconomic to operate and are no longer “used and useful.” CalCCA contends that the problem lies in the former, as the plants continue to deliver valuable services. The failure of the PCIA benchmark to capture the full value of the portfolio, however, requires correction.

The answer to this cost versus value problem is not to circumvent the market through a mandatory allocation of capacity. The answer lies in selecting reasonably representative values among the range of possible value indicators in the near term and, in the longer term, fostering the development of a transparent, liquid capacity market in which prices will reflect value.

II. ESTABLISHING A SUBSTITUTE FOR THE CURRENT RPS BENCHMARK FOR USE WHEN THERE ARE NO “NEWLY DELIVERING” RPS RESOURCES IN THE JOINT UTILITIES’ PORTFOLIOS WILL ENSURE A ROBUST BENCHMARK

The Joint Utilities and TURN propose to eliminate the PCIA benchmark entirely based in part on their view that the Green Adder benchmark does not provide a
reasonable proxy value. They reason that the current benchmark overstates the actual value of the resources because it relies on “newly delivering” RPS projects procured “by the Joint Utilities only.” In addition, the Joint Utilities observe that they are “long on renewable energy and are no longer procuring renewable resources unless required to do so.”

AReM/DACC also argue that the Green Adder is flawed, explaining:

When the IOUs were entering into many new contracts, such as was the case in the early 2010s, there were sufficient new contracts each year to represent a “market price.” Now that the IOUs are nearing or exceeding their RPS targets, there are fewer new contracts beginning delivery, and an increasing likelihood that there will be years when there are no new contracts. AReM/DACC further explain, consistent with the views of CalCCA, the Joint Utilities and other parties, that the DOE component of the Green Adder is flawed. AReM/DACC propose, instead, to replace the current Green Adder with the Platts market index for a PCC 1 REC.

CalCCA proposed in its direct testimony to retain the current formulation. Departed customers pay PCIA for resources which were deemed cost-effective at the time they were signed. The result is that PCIA costs continue to increase for years after a customer departs, as more and more contracts begin delivery. CalCCA does not contend that CCA customer should receive the value of resources when they were signed, but supports the continued use of a multi-year average of newly delivering

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38 Joint Utilities Direct Testimony at 2:15-2:18; TURN Direct Testimony at 7-8.
39 id. at 1-14 – 1-15.
40 id. at 1-15.
41 AReM/DACC Direct Testimony at 14.
42 id. at 15.
contracts as a reasonable solution to address the lag between contract approval and
delivery.

CalCCA agrees with AReM/DACC that the Green Adder may have limitations
when the Joint Utilities are no longer procuring RPS contracts. The limitations,
however, do not appear to be near-term limitations. Based on the information provided
in the ALJ Data Matrix submissions of the Joint Utilities, it appears that over the next
few years, approximately 600 MW of new RPS resources will begin delivery to PG&E,
2,300 MW to SCE and 134 MW to SDG&E. Consequently, if CalCCA’s proposed near-
term and longer term solutions are adopted, the existing RPS benchmark should be
sufficiently robust to serve the PCIA benchmark purpose. Where no robust data are
available to inform the existing Green Adder, the Commission may want to evaluate the
suitability of the IRP results as an alternative proxy.

If periods were to arise without newly delivering resources to inform the Green
Adder, CalCCA disagrees with AReM/DACC that the use of the Platt’s index is
appropriate for all RPS resources. This index represents short-term value, which may
not represent the price of acquiring long-term resources, nor the cost of regulatory
compliance with long-term contracting requirements. Consequently, it suffers from the
same flaws as the use of the 2016 RA Report to assess the value of capacity — it
ignores the majority of RPS that is procured via long-term PPAs and instead focuses on
a small subset of short-term transactions that are being done by LSEs to rebalance their
portfolios. Moreover, as CLECA observed in its proposal for the adoption of the Green
Adder, “most of the renewable compliance will come from renewable generation contracts, not REC contracts.” 43

Finally, the Joint Utilities assert that contracts for “newly delivering” resources, should not be used because the Green Adder then lags current market prices for RPS purchases. 44 The Joint Utilities made this argument in 2011, arguing that “[i]f IOU cost rather than market value is used for the MPB, and the MPB is then compared to the same costs in the IOU portfolio, PG&E contends that there will never be a difference between the MPB and the IOU portfolio cost.” 45 The argument made in 2011 was simply not true; the benchmark under the Green Adder does not remain at cost, except for the first year of deliveries; thereafter, the resource will be benchmarked against more recent newly delivering resource prices. In addition, projects can be cancelled between the date of contract execution and the online date, or project costs (and contract prices) can increase as a developer gets closer to commercial operation. Using prices for resources contracted during the benchmark year can understate the ultimate cost of the resource. Further, relying on contracted, rather than newly delivering resource prices virtually cements the notion that from the first moment of operation, resources procured at or below the values set by Commission can be uneconomic. While the Commission’s planning values may diverge from market prices over time, accepting that a resource is dramatically devalued on its first day of operation calls into question either the method for valuing the resources in the procurement process or the method for valuing the

43 D.11-12-018 at 21.
44 Joint Utilities Direct Testimony at 2-15 – 2-16 (“Because the Joint Utilities’ newly-delivering renewable resources are the result of contracts that were executed several years prior to the commencement of deliveries, the RPS adder lags actual market prices for newly-contracted renewable resources and fails to reflect the market price utilities could obtain through sales of those resources.”). See also App. B-28.
45 D.11-12-018 at 15.
resources in the benchmark. On balance, continuing to benchmark at the price of newly
delivering resources is the best alternative, particularly as the Commission is developing
a more market-based, durable framework for procurement cost responsibility.

III. PG&E’S PRIOR ASSERTIONS AND OPERATING DATA FOR GHG-FREE
RESOURCES SUPPORT ADDING A GHG-FREE VALUE MEASURE TO PCIA
BENCHMARK

CalCCA proposed the integration of a value for the “GHG-free” attribute of
nuclear and hydroelectric UOG, pointing out that the Commission, PG&E and the
market generally agree that this attribute has value. No other entity has proposed
including a GHG adder. The Joint Utilities’ failure to acknowledge this value, however,
is undermined by PG&E’s testimony in the DCPP proceeding and the analysis of
operating data for GHG-free resources.

In A.16-08-006, PG&E addressed the retirement of Diablo Canyon. PG&E
recognized that Diablo Canyon’s generation was unique in that it was GHG-free, and
proposed that its generation be replaced by GHG-free generation, even if the GHG-free
generation was at a higher cost than gas-fired generation. PG&E requested that “the
Commission adopt a policy directive that the output of Diablo Canyon be replaced with
GHG-free resources.” PG&E also recognized that the value of GHG-free generation
was comparable to the value of RPS generation and proposed that the appropriate
measure to evaluate the cost-effectiveness of GHG-free generation was to use the cost
of RPS resources as a proxy. PG&E stated: "The RPS cost cap proposed for Tranche
#1 solicitation is a reasonable way to define cost-effectiveness in the context of GHG-

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46 CalCCA Testimony at 2B-10 – 2B-11.
47 A.16-08-006, PG&E Rebuttal Testimony, at 36.
free resource procurement." PG&E indicated that this approach to cost-effectiveness be applied to GHG-free resources.

In addition, as mentioned in Section I, Diablo Canyon's ongoing, avoidable costs of operation are uneconomic unless a value of $4/MWh or more is assumed for its generation being GHG-free (in addition to an $85/kW-yr capacity price). PG&E's decision to incur these high costs is unreasonable, and adds to bundled and departing customers costs, unless it is offset by both the higher capacity benchmark and an additional GHG-free value. In that Application, PG&E benchmarked GHG-free generation cost-effectiveness in $2016 as $82/MWh.

IV. TREATMENT OF UNMARKETABLE EXCESS PRODUCTS IN THE UTILITY PORTFOLIO

The Joint Utilities and TURN suggest that there may be periods when not all products will be marketed, and the value of those resources in the benchmark should be zero. Lack of long-term portfolio management should not be mistaken for lack of a market. Resource development never results in the precise quantity of resources being procured to match LSE’s spot needs. Where utilities build capacity resources that outstrip need, they should be offering these resources in the long-term market to the LSEs that are serving load. Moreover, even if a product is not marketable in the short-run it retains optionality value. For these reasons, the proposal to value the resources at zero should be rejected.

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48 Id. at 32 (emphasis supplied).
49 TURN Direct Testimony at 10:8-11.
50 See CalCCA Testimony at 2B-11:3-5.
51 See Joint Utilities Direct Testimony at 1-14:3-4 and 2-3:18-19; TURN Direct Testimony at 10:9-11.
V. MODIFICATION OF THE EXISTING PCIA IS APPROPRIATE IN THE TRANSITION TO A MORE DECENTRALIZED END STATE

A number of parties in this proceeding, including the Joint Utilities and TURN, agree that “the market is the right benchmark for assigning costs.” The Joint Utilities also point out that “the Commission has expressed a desire to rely on prices from transparent and liquid markets when such markets for portfolio attributes exist.”

CalCCA agrees that, in theory, a benchmark built on market values provides the best solution. Taking this approach when representative markets are illiquid, non-transparent and artificially depressed as a result of regulatory mandates, however, results in a cost shift from bundled to CCA and DA customers. Relying on short-term market prices under these conditions undervalues the products held in the utility portfolio and commensurately increases the PCIA rate. By paying a PCIA rate that undervalues resources held in the long-run to serve bundled customers, departing load subsidizes the cost of those resources relative to their value.

Recognizing the shortcomings of existing “market” prices, CalCCA has proposed a longer term solution – the Staggered Portfolio Auction – to create more reliable market prices. The SPA not only offers more reliable prices, it offers a more durable solution for the utilities and their bundled customers in a market in which the utilities are projected to be at risk for losing up to 85% of their load to non-utility suppliers. The SPA contemplates offering 100% of the utilities’ GHG-free and RPS resources into the market, making them available to other LSEs or market participants. It also allows the

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52 Commercial Energy Direct Testimony at 10; see also Joint Utilities Direct Testimony at 2-10; TURN Direct Testimony at 5.
53 Joint Utilities Direct Testimony at 2-9.
54 See id. at 1-9 (“The success of California’s RPS program has created a surplus of RA and RECs which, in turn, has driven down the price for these products.”).
utilities to buy back the resources they need to serve their customers at more reliable market prices.

Until prices transparently reflect a broader, liquid market, however, a PCIA benchmark based on administratively set values remains the best solution. The Commission, as the Joint Utilities observe, is no stranger to the struggle to value products and attributes in a hybrid market. The Commission has invested substantial time and resources into developing long-term values for a range of purposes, as highlighted in CalCCA’s opening testimony. It should not now default to the Joint Utilities’ rejection of any valuation of portfolio products and attributes and mandatory product allocation simply because valuation is challenging or because precision is unattainable. Informed by this record, the Commission should use its best judgment to choose market benchmark values that fairly and fully assess the Joint Utilities’ portfolios.

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55 Joint Utilities Direct Testimony at 1-9.
56 CalCCA Testimony, Table 2A-3 at 2-11.
CHAPTER 3

GOING FORWARD UTILITY PORTFOLIO OPTIMIZATION
(Common Outline §III)
I. THE JOINT UTILITIES EFFORTS TO MANAGE PORTFOLIO RESOURCES TO ADDRESS DEPARTING LOAD HAVE BEEN LIMITED, AND THE PURPOSE OF PG&E’S MOST RECENT EFFORTS IS SUSPECT

The Joint Utilities claim that “[a]s a standard practice, each of the Joint Utilities routinely conducts portfolio management activities to align supply obligations with the needs of bundled service customers. These activities include the procurement and/or sale of energy and energy products pursuant to each investor-owned utility’s (IOU) Bundled Procurement Plan (BPP) and Renewables Portfolio Standard (RPS) Plan.”57

The Joint Utilities’ claim is not supported by the evidence.

The data summarizing the actual portfolio optimization activity conducted by the utilities demonstrate that both PG&E and SCE conducted almost no activity to manage portfolio volumes until the past few months leading up to the deadline for filing testimony in this case. Notably, they have also undergone a step-change increase in their sales activities. The graphs below and in CONFIDENTIAL Exhibit 3-A show the activity for: 1) RA Capacity sales over the last ten years as reported by utilities58 and 2) the activity for the last nine years of RPS energy sales as reported by the utilities.59 The utilities did not provide the results of PG&E’s recent RPS energy sales Request for Bids.

57 Joint Utilities Direct Testimony, Chapter 3, Section B, 3-1:18-23.
58 SCE and PG&E provided data in response to CalCCA Question 4-6, attached to CalCCA’s Opening Testimony as CONFIDENTIAL Exhibit 3-G, referenced at 3-14.
59 SCE and PG&E provided data in response to CalCCA’s Question 4-6, attached to CalCCA’s Opening Testimony as CONFIDENTIAL Exhibit 3-G, referenced at 3-14.
Figure 3-1

IOU Sales of RA Capacity (Monthly MW)

PG&E RA  SCE RA


(YTD Proposed Sales)
PG&E addresses the outcome of its 2018 Multi-year RA Sales Solicitation as follows.\(^{60}\)

Ultimately, the RA solicitation was broadly subscribed, with 16 entities providing bids to PG&E. PG&E is currently in the process of evaluating the bids received and shortlisting potential transactions. Despite robust participation, it is clear that market interest in PG&E’s multi-year RA Product is insufficient to fully monetize the long RA position PG&E currently holds due to departing load. Based on bids received, PG&E estimates that no more than 33 percent of its long system RA position will be monetized through the RA Solicitation.

The utility testimony provides an incomplete picture of both the solicitation process and the results for RA. PG&E issued its solicitation on March 15, 2018 for RA compliance years 2019 – 2022. Bids were due on March 23 with the short list to be determined on April 2, 2018 (the same day as direct testimony was due in this case). The solicitation

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\(^{60}\) Joint Utilities Direct Testimony, Chapter 3 at 8:14-19.
was held outside of the normal timing for the year-ahead RA compliance procurement (summer through early fall would be more typical) and included an atypically long term. Additionally, the 8-day response for such a long-term, high volume procurement is a deterrent to optimal participation and value extraction. It appears possible that collecting data points to support the Joint Utilities’ arguments in the instant case may have trumped the prudent management of the assets entrusted to PG&E. In any case, despite the flawed implementation of the RFB, significant interest was generated in the RA products. For the 2019 compliance year, PG&E sold 36% of its excess system RA position and is still a few months from the normal commencement of RA solicitation for this period. While the percent sold for the later years is lower, the utilities’ claim that interest is too low to fully monetize its position is unsupported. If PG&E were to make a multi-year RA offering annually, it would still have one, two or three additional opportunities to monetize the years 2020-2022. With appropriate notice and signaling to the market of its willingness to offer these products, there is no reason to expect that they would not be fully subscribed. In addition, appropriate notice could be expected to not only improve participation, but the price garnered for these resources as well.

PG&E also addresses its Long-term RPS Contract Sales Solicitation issued on February 20, 2018, in which it sought potential buyers to assume PG&E’s interest in long-term solar PPAs with terms of 11-15 years and up to 150 MW. PG&E observes that only five entities expressed interest, with no CCAs participating, and concludes that “there was insufficient interest and the RFB did not result in any executed transactions.” While we have no information from PG&E to illuminate why no CCAs

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61 Joint Utilities Direct Testimony at 3-6:24-27.
62 Id. at 3-7:11-12.
participated, the paucity of previous RFBs for RPS products and the alignment of the RFB with the PCIA testimony due date made PG&E’s RFB suspect. Moreover, CCAs could not be certain at this point how any long-term commitments they might have made would be addressed in the context of this proceeding, particularly if PG&E were to add another mandatory RPS allocation on top of any procurement from the RFB. These factors did not create an environment likely to maximize either participation or value extraction.

While PG&E provided feedback on the RA and solar solicitations, it chose not to provide any feedback regarding the bids it received for RPS energy. This was despite the fact that bids were due on February 27, 2018, more than two weeks prior to the due date for direct testimony in this proceeding and five weeks prior to the due date for rebuttal testimony.

Finally, the Joint Utilities testimony suggests that PG&E is “also participating in solicitations conducted by CCAs.” Although we have not reviewed any CCA RFO results, based on informal conversations we understand that the utilities’ participation in CCA solicitations has been limited. Our impression is that the utilities have been more inclined to push the CCAs to participate in the utilities’ own solicitations than to compete seriously in the CCAs’ solicitations. The focus on the three last-minute solicitations conducted by PG&E in early 2018 would seem consistent with that conclusion.

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63 Joint Utilities Direct Testimony at 3-6:22-23.
CALIFORNIA COMMUNITY CHOICE ASSOCIATION
REBUTTAL TESTIMONY

CHAPTER 4

PCIA ALTERNATIVES
(Common Outline §IV)
I. THE JOINT UTILITIES’ “GREEN ALLOCATION MECHANISM” AND “PORTFOLIO MONETIZATION MECHANISM” DO NOT COMPORT WITH STATUTORY AUTHORITY AND RESULT IN LOST VALUE FOR DEPARTING LOAD CUSTOMERS

A. The GAM Runs Contrary to Public Utilities Code §366.2(a)(5).

A foundational principle for CCA organization was embraced by the Legislature in 2011 through the enactment of SB 790. Section 366.2(a)(5) provides:

A community choice aggregator shall be solely responsible for all generation procurement activities on behalf of the community choice aggregator’s customers, except where other generation procurement arrangements are expressly authorized by statute.64

To date, the only generation procurement by an investor owned utility permitted on behalf of a CCA is limited RA procurement. Section 365.1(d)(2)(C) permits the utility to allocate RA benefits of resources to customers who pay the resources’ net capacity costs, a process the Commission has implemented as the Capacity Allocation Mechanism.

The GAM is not authorized by statute, yet, the GAM simulates the CAM;65 products or attributes from the GAM-eligible resources – limited to RA and RECs – are involuntarily allocated to LSEs, and all remaining products or attributes are monetized in the short-term market.66 The LSEs are then required to pay the “net costs” of these resources, equal to the total resource cost less the revenues received in the short-term market.67 Consequently, by allocating RA and RECs to CCAs, the Joint Utilities are infringing on the CCAs’ statutory authority to be “solely responsible” for their procurement.

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65 Joint Utilities Direct Testimony at 4-9.
66 See generally, Joint Utilities Direct Testimony at 4-22 – 4-29.
67 See id. at 4-30.
Beyond this legal distinction, the utilities reliance on CAM as a precedent is misplaced. The CAM was instituted prior to the development of CCAs. LSEs serving DA customers at the time CAM was created may not have been interested in developing new resources, resulting in a perceived need for utilities to step in. However, CCAs are not the same as LSEs serving DA customers a decade ago. CCAs have been and plan to continue to develop new resources themselves. Evidence of this direction can be found in the procurement mechanisms and tariffs of existing CCAs. There is no demonstrated need for the utilities to acquire resources to meet the needs of CCA customers as CCAs have been statutorily authorized to do it themselves.

B. The GAM is a Mandatory Product Allocation Rather than a Cost Reimbursement Mechanism, Contrary to Public Utilities Code §366.2(f)(2).

Section 366.2 makes clear that CCA customers will be bound to pay certain utility costs following their departure, including CDWR Bond and Power Charges, certain balancing account charges and specified utility procurement costs. Specifically, subsection (f) provides:

A retail end-use customer purchasing electricity from a community choice aggregator pursuant to this section shall reimburse the electrical corporation that previously served the customer for all of the following:

- 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

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68 See, e.g., infra at 7-4.
70 Id. §366.(f)(1).
community choice aggregator, through the expiration of all then existing electricity purchase contracts entered into by the electrical corporation.\textsuperscript{71}

Consistent with §366.2(a)(5), which prohibits utility procurement on behalf of a CCA, this provision contemplates “reimbursement” for “costs,” not the involuntary allocation of products and attributes. While §366.2(g) contemplates that the calculation of departing load charges should take into account any allocated benefits, this provision itself does not authorize an allocation of resources and/or underlying attributes.

C. The GAM Materially Impairs the Rights of a CCA to Be Solely Responsible for Procurement.

The mandatory allocation of RA and RECs on CCAs will have a significant impact on their portfolios and impair their ability to control their procurement strategy. The allocation would constitute:

- Up to 96% of a CCA’s 2020 RPS requirement and up to 50% of its 2030 requirement.
- Up to 44% of a CCA’s System RA requirement when combined with the existing CAM allocation.

To provide a visual representation of the problem, the graphs below are an illustrative example of hypothetical CCAs, located in SCE’s and PG&E’s service territories, with a usage forecast of 1,000 GWh — based on projected loads through 2030.\textsuperscript{72} The graphs show the MWh of RPS-eligible energy allocation to the illustrative CCA that would occur through the GAM, separating the RPS-eligible resources by vintage. A vintage 2017 CCA in PG&E’s service territory would, in 2020, receive an allocation of roughly 263,000 MWh of RPS-eligible energy, or 80% of its 33% RPS compliance obligation for 2020.

\textsuperscript{71} Id., §366.(f) (emphasis supplied).
\textsuperscript{72} A CCA serving 1,000 GWh would constitute approximately 1.25% of each utility’s service territory load.
A vintage 2017 CCA in SCE’s service territory would, in 2020, receive an allocation of over 317,000 MWh of RPS-Eligible Energy, or 96% of its 33% RPS compliance obligation for 2020.
Allocation of RA credit would also have a material impact. The illustrative vintage 2017 CCA in PG&E’s service territory would, in 2020, receive an allocation of roughly 51 NQC MW of System RA Credit under the GAM; combined with the existing CAM allocation of 14 MW, the utility will have procured a total of 65 MW, or 29% of the CCA’s 228 MW RA requirements.
The illustrative vintage 2017 CCA in SCE’s service territory would, in 2020, receive an allocation of roughly 48 MW of System RA Credit under the GAM; combined with the existing CAM allocation of 51 MW, the utility will have procured a total of 99 MW, or 44% of the CCA’s 228 MW RA compliance requirements.
Figure 4-4

A CCA who is already 60% resourced could suddenly have excess or stranded capacity in its portfolio.

Figure 4-5
The GAM/PMM amounts to a move by the Joint Utilities to involuntarily force resources into CCA supply portfolios, leaving CCAs little space to compete on price or to choose their preferred sources of energy and capacity to serve their customers’ needs. They may be limited to compete on little or none of the RPS compliance requirement and no more than 44% of the RA compliance requirement. Moreover, today a CCA has virtually no room to compete on energy price because the “benchmark” is effectively the forward strip for the short-term energy liquidation value—a price that is virtually impossible to beat. If the Commission authorizes the GAM, it will have left CCAs anything but “solely responsible” for their own procurement, including hampering the CCAs’ ability to procure local resources, prevent rate shock, control their own procurement or realize the other intentions of the Legislature when it authorized for the formation of CCAs.
D. The GAM Does Not, Contrary to Joint Utilities' Claims, Preserve All Short-, Medium- and Long-Term Value of the Resources

The Joint Utilities have proposed the GAM as the means to allocate the costs and benefits of the RPS-eligible and large hydroelectric resources in their portfolios for setting the PCIA. The Joint Utilities would allocate to LSEs a load-based pro rata share of the total costs, as well as the RECs and RA capacity, for these resources, and also credit LSEs with a pro rata share of the revenues from the liquidating energy and ancillary services from these resources.\(^7\) The Joint Utilities-proposed GAM is flawed in several material respects.

First, the GAM fails to recognize, let alone capture and preserve, the wider range of values inherent in the RPS-eligible and Large Hydro resources included in the GAM allocation, including GHG-free energy value, hedge value and other products. The Joint Utilities' proposals once again recognize only three material products in their portfolios: energy, RA and RECs. Although GAM would allocate the RA and REC attributes to LSEs, the only other benefit stream to offset the full costs of the resources is the market revenue from the sale of energy and ancillary services; all other potential values would be wasted, raising costs for all customers.

Second, the GAM fails to capture and convey the incremental value from the optionality associated with the resources, which could be significantly greater if allocated to LSEs rather than liquidated in the energy market. Notably, the significant optionality value that is derived from flexible storage, dispatch, ramping and arbitrage capabilities inherent in the Large Hydro (including pumped storage) resources would be liquidated in the market but not allocated to the LSEs responsible for paying the costs of

\(^7\) Joint Utilities Direct Testimony at 4-5.
Similarly, flexibility in the administration of RPS resources (e.g., curtailment provisions, term extensions, price resets, etc.) would be lost under the proposed GAM allocation of only RA and REC attributes.

Third, the Joint Utilities’ claim that giving CCAs credit toward the 10-year contract commitment for RPS resources under GAM gives them the value of a long-term asset is false. In fact, the GAM proposal fails to capture and convey to the CCAs the long-term value of the assets in question. The process of planning, constructing and/or contracting for resources to meet customers’ long-term needs takes years to complete. A short-term allocation of RA and REC attributes does nothing to relieve CCAs of the need to plan and execute long-term procurement of resources, which they are already required to do by statute.

E. The PMM Does Not, Contrary to Joint Utilities’ Claims, Preserve All Short-, Medium- and Long-Term Value of the Resources

The Joint Utilities have proposed the Portfolio Monetization Mechanism as the means to value the conventional nuclear, gas and energy storage resources in their portfolios for setting the PCIA. The Joint Utilities would offer these assets into the CAISO spot markets and offset the resource costs with those market revenues. The net resource costs would then be collected from departing load customers.\(^74\) Like the GAM, the PMM is flawed in several material respects.

First, the proposed liquidation of PMM resources in CAISO spot markets\(^75\) prevents realization and conveyance of the full value of PMM resources. The PMM would merely transfer costs to CCAs without any transfer of control over the resources.

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\(^74\) Joint Utilities Direct Testimony at 4-9.
\(^75\) Id., (“...the eligible resources be bid or sold into energy and A/S markets in accordance with the Commission’s LCD [least cost dispatch] protocols...”).
themselves – a proposal that does little to resolve the fundamental issues of the current PCIA methodology. The value of energy resources is more fully realized and maximized when conveyed between counterparties via forward contracts and forward contract prices, not through the spot market prices that the CAISO uses for short-term dispatch and settlement. While liquidation in CAISO markets may be the easiest and simplest way for the Joint Utilities to rid themselves of the responsibility to manage the PMM resources, the proposal fails to capture the full value of those resources to the detriment of all customers.

Second, the PMM also fails to recognize, capture and preserve the wider range of values inherent in the resources included in the PMM allocation. While the PMM would provide a financial settlement from liquidation revenues from RA, energy and ancillary services, all other potential value streams would go unrealized, including notably the value of the GHG-free energy available from the nuclear resources or the intrinsic forward gas-conversion tolling value of the gas resources would go unrealized.

Third, the PMM fails to capture and convey the incremental value from the optionality associated with the generating resources, which could be significantly greater if allocated to LSEs rather than liquidated in the energy market. Generation assets are “real options” with significant extrinsic option value stemming from the ability to adjust dispatch operations upward or downward in order to capture incremental value in response to short-term price volatility that, by definition, cannot be captured by liquidation of energy at the time of expiration of the option in the spot market. A portfolio of generation assets provides substantial optionality value to an entity engaging in active portfolio management, yet the PMM would deny that optionality to the LSEs that
are paying the costs of resources under the PMM. Notably, the significant optionality value inherent in the gas-fired generation and energy storage resources in the PMM portfolio, such as extrinsic optionality value for flexible gas generation, and energy price arbitrage for storage, would be lost under the proposed PMM allocation because the resources would be liquidated in the spot market without being fully realized.

Fourth, liquidating resources at CAISO spot balancing market prices wastes value because it involves selling at prices that are routinely depressed and unlikely to ever rise to the level required to support new resource development. LSEs generally are required to secure 115% of their projected peak load requirements under California’s RA program. Mandated excess reserves coupled with other policy provisions such as the CAISO bid price offer cap and the prohibition against underscheduling, will tend to suppress CAISO spot balancing prices for most periods of the year to a level that, as discussed further in Chapter 2A of CalCCA’s rebuttal testimony, has never justified the procurement of any new resource. The proposal to value PMM resources for departing load cost responsibility determinations using these same, inadequate CAISO spot market prices is inappropriate and inequitable.

F. The GAM and PMM Do Not, Contrary to Joint Utilities’ Claims, Generate Predictable Outcomes Compared to the PCIA

The Joint Utilities claim that the GAM and PMM provide predictability to departing load:

The proposed GAM and PMM generate predictable outcomes compared to the PCIA, because fewer variables impact the net costs allocated to the departing load customers. Resource costs will be predictable over time, because a significant portion of each utility’s Eligible Portfolio is comprised
of renewable contracts that generally have fixed prices and predictable quantities over time.\textsuperscript{76}

The Joint Utilities’ claim is incorrect. What the joint utilities have recommended through their GAM/PMM proposal is a short-term allocation of attributes or spot market attribute liquidation value for long-term products. The quantities will vary from quarter to quarter for RECs and month to month for RA, but they will not be known precisely for RPS until after the fact.\textsuperscript{77} The utilities remain owners of the assets and are free to dispose of them as they wish and at prices they consider reasonable with timing they manage to fit their needs.\textsuperscript{78} Some CCAs have already procured resources for their customers and would be forced to liquidate excess (the precise volume of which would be unknown) in the short-term market. Other CCAs would have to guess what volume was going to be allocated not just for the current year, but for at least the number of years it would take to procure long-term (10-years plus) resources in the market. Since utilities can and have indicated that they will continue to attempt to sell excess resources, CCAs could never know whether these resource attributes would be available to them from one period to the next. The result of this proposal would be a portfolio that is un-hedgeable, unmanageable and whose costs are highly volatile.

The Joint Utilities also claim that the GAM provides customers “with direct resource value for their departing load charges and serving as a long-term hedge against fluctuations in the prices for those products (symmetrical to the functions those resources serve for bundled service customers). Importantly, these allocations will also

\textsuperscript{76} Joint Utilities Direct Testimony at 4-35:21 – 4-36:4.
\textsuperscript{77} Id. at 4-6.
\textsuperscript{78} Joint Utilities Direct Testimony at 3-5:11-14: “…the Joint Utilities will actively explore opportunities to increase their sales of renewable products, or reduce or terminate purchases, when doing so is deemed by the IOU to be commercially reasonable.”
ensure that the substantial existing preferred-resource commitments, made by the Joint Utilities on behalf of customers are efficiently accounted for in the collective planning and procurement processes of all LSEs, and avoids the potential for costly double-procurement and potential stranding of policy-preferred resources.79

Again, the Joint Utilities’ claim is incorrect. Since these attributes would be assigned on a short term, and for RECs, after the fact basis through GAM, they would not serve as a long-term hedge as claimed by the Joint Utilities. Rather, such an allocation would further hamper the ability of the CCAs to predict and manage costs and hedge their own portfolios. Since the CCAs would not own or control these assets, the Joint Utilities would be free to sell or dispose of them at their own discretion; the volumes would only be made available quarterly for RPS and monthly for RECs. The CCAs would face greater uncertainty and be put in a situation where it would be more difficult, and more expensive, to hedge and manage their position than it is today. Since CCAs have an inclination as public agencies to use public oversight of portfolio hedging practices as core principle of CCA governance, to ignore the hedging value to CCAs is a serious error.

Not knowing from one short-term allocation to the next what attributes would be dumped on them by the utilities, CCAs would be forced to continue to engage in resource planning that would involve building assets or acquiring long-term assets through contracts that they control and that provide a hedge to their load obligations. Allocated resources could come and go from one period to the next and would be of uncertain quantities which for RPS would not be fully known until after the fact. The short-term nature of the allocations for RECs and RA and the liquidation of energy in the

79 Joint Utilities Direct Testimony at 4-6:10-21.
CAISO spot market will result in revenues equivalent to a fraction of the assets potential value.

G. The GAM and PMM Put the Utilities in a Position of Market Power in an Increasingly Competitive Market

Despite the increasing growth of suppliers and buyers in the market, the GAM and PMM would place the Joint Utilities in a position of market power by avoiding reliance on any market mechanism to require allocation. The GAM and PPM do nothing to address the predicted end state where the Joint Utilities have only 15% of the load but hold 85% of the assets. This gross imbalance unnecessarily risks market manipulation and anti-competitive behavior that would harm all customers. Utilities would not only control the assignable assets, they would have superior knowledge of the expected resource volumes, planned resource maintenance, forced resource outages, and planned sales of allocable resources. This superior knowledge and asset control would provide them with a highly unfair advantage to compete to supply generation to CCA or other departing load customers.

Further, since utilities control the timing of sales to third parties, they would be most likely to initiate term sales of allocable resources when the market was short, and prices were high. CCAs that attempted to rely on short-term allocations of the attributes from such assets would likely find themselves without the benefit of those attributes precisely when they could least afford to be short in the spot market. Prudent planning would require them to cover their needs with assets contracted in the long-term market that are under their control.

Utilities control a large share of the aggregate quantity of RA and RPS resources available to the market. Currently, they are hampered in their ability to impact spot
market pricing because they have significant load that offsets their generation positions. If utilities were to lose 80% of their load as they have postulated is possible and which they hold out as a primary driver for the need to modify the PCIA process, their net long generation position could create a market power issue. Given the potential harm an IOU could cause a CCA, the standard of care and oversight on this matter should be high. CCAs operate in an asymmetric market in which an IOU can cause CCA customers to experience higher generation (PCIA) costs. This means an IOU has a significant level of control over the cost risk that may drive CCA customers to opt out of CCA service. Such a situation should not be exacerbated as the GAM/PMM proposal would do.

II. TURN’S VOLUNTARY RETAIL SELLER SUBSCRIPTION RAISES QUESTIONS OF FEASIBILITY AND CARRIES SOME OF THE SAME WEAKNESSES AS THE GAM/PMM

TURN offers the following “alternative approach to manage output and attributes from the IOUs’ PCIA-relevant resources’ output and attributes that might increase their market benefits and/or enhance Retail Sellers’ portfolios.”

TURN labels this the “Retail Seller Subscription” option, which appears to be effectively a voluntary GAM/PMM. The utilities would allocate resources and output and attributes to CCAs but would continue to be the counterparties to contracts and to own their own resources. As with GAM/PMM, CCAs “would assume responsibility for the payments and other considerations made under such contracts; assumption of such obligations would lead to an equivalent reduction in PCIA charges.”

Also, like GAM/PMM, the product and attribute allocation would be from “existing California-owned low GHG

80 TURN Direct Testimony at 16-19.
81 Id. at 16:27 – 17:1.
resources, including renewable resources procured in compliance with the RPS or existing IOU hydro resources.82 While this approach is an improvement over the mandatory GAM/PMM, it raises questions of feasibility and carries some of the same weaknesses as the GAM/PMM.

TURN contemplates that this option would give CCAs “the option to direct, to some degree, the IOUs on how to ‘manage’ such resources, such as how to schedule or bid such resources into the CAISO’s energy markets.”83 The CCAs could also:

- Use the attributes for RA compliance.
- Receive market revenues for sale of the output from the resources.
- “[D]irect the IOUs to engage in forward sales of the output of such contracts.”84

According to TURN, this method would require some means for allocating to Retail Sellers bundled customers’ existing utility resources.85 CalCCA appreciates the focus that TURN places on the importance of retail LSEs having some control over the make-up of assets in their portfolios, the scheduling of those assets, the ultimate disposition of those assets and the ongoing level of its exposure to the PCIA. We find it hard to envision, however, the degree of asset control TURN contemplates and, at our current level of understanding, believe that the Retail Seller Subscription would suffer from the same shortcomings identified for the GAM and PMM, above.

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82 Id. at 17:3-6.
83 Id. at 17:7.
84 Id. at 16:24-27.
85 Id. at 15-18.
III. COMMERCIAL ENERGY’S PROPOSAL FOR AN AUCTION MOVES IN THE RIGHT DIRECTION

We agree that there are elements of the Commercial Energy “Voluntary Allocation & Auction Clearinghouse” proposal that are superior to the Utility GAM and PMM. Specifically, Commercial Energy provides for voluntary, open and transparent allocation and auction processes as the preferred method of determining value and assigning attributes. These are important elements that are missing in the GAM and PMM.

However, the Commercial Energy proposal fails to capture the full value of the utility assets due to: 1) the inadequate transfer of rights and control over the generation assets under the proposed voluntary allocation mechanism, 2) the limited set of attributes represented as a proxy for full market value for the long-term assets held by the utilities, 3) the short-term nature of the action, and 4) the apparent omission of the UOG generation assets from the VAAC proposal.

First, under the Commercial Energy VAAC proposal, there would be no transfer of PPA contract rights or generator operational control to the LSE accepting an allocation share or winning any auction share of the portfolio. Those would remain entirely with the IOU and thus the VAAC allocation appears to be indistinguishable from the IOUs’ GAM/PMM proposal. For all the reasons described elsewhere in this testimony, the VAAC would suffer similar flaws as the Joint IOUs’ primary proposal in this case.

Second, the VAAC proposal, like the Joint Utilities’ GAM/PMM proposal, appears to erroneously conclude that value to be derived from the resources in the PCIA-eligible supply portfolios is limited solely to energy, RECs and RA Capacity. As discussed in
detail elsewhere in CalCCA's testimony, this fails to capture and convey to the departing load customers responsible for paying the costs of the resources, the other substantial sources of value inherent in these resources.

Third, short-term auction sales do not produce equivalent commercial value or provide adequate hedge benefits to avoid cost shifts from utility customers to CCA customers or to prevent double procurement of assets. As Commercial Energy's Ron Perry states "the VAAC system functions more like a long-term contract than a spot, hour-, or day-ahead sale because it takes place and closes a month before the delivery period for the contracts each quarter." While CalCCA agrees that a sale process that closes a month before delivery is preferable to forced allocation of attributes or spot liquidation value as a proxy for asset value, the short-term auction process suggested by Commercial Energy fails to capture the full value of the assets as represented by a long-term asset contract or plant ownership.

Fourth, the VAAC proposal apparently fails to provide a solution that adequately addresses, the GHG-free, Legacy UOG nuclear and hydro resources or UOG storage resources that are part of the Joint Utilities' current PCIA-eligible portfolios. Commercial Energy states the "UOG contracts should clearly be included in the PCIA calculation and in the VAAC process that Commercial Energy proposes" but it is unclear what is meant by "UOG contracts" and what, if any, UOG resources Commercial Energy has in mind since it says that "[t]he ratio of UOG to third-party contracts in the PCIA appears to be small, however." Perhaps this indicates Commercial Energy's view that recovery of UOG asset costs from departing load customers is not permissible or should be

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86 Commercial Energy Direct Testimony at 12:12-14.
87 Id. at 14.
88 Id. at n.20.
discontinued but since this is left unexplained in Commercial Energy’s testimony, CalCCA is unclear exactly what is being proposed.
CHAPTER 5

PCIA “CAPS” AND “SUNSET”
(Common Outline §V)
I. THE 10-YEAR LIMITATION ON RECOVERY OF “NEW WORLD” FOSSIL GENERATION COSTS SHOULD REMAIN IN PLACE

The Joint Utilities propose to expand the scope of PCIA-eligible UOG by lifting the existing 10-year limit on allocation of post-2002 fossil generation costs to the PCIA.\(^{89}\) The Commission has addressed and retained this limitation in three decisions, leaving the door ajar for further discussion under specific circumstances. The utilities’ attempts to lift the limitation – 15 years after its first implementation – are unsupported and unjustified.

The Commission first adopted the limit in 2003 in approving SCE’s Mountainview Generating Station, based on a proposal offered by TURN.\(^{90}\) Mountainview was presented as a “unique opportunity” by SCE, but opposed by ORA and TURN as a “unique burden.”\(^{91}\) TURN argued that “if Mountainview, Mohave, and direct access all converged simultaneously it could place bundled customers at serious risk of ‘rate shock.’” ORA further argued that Mountainview would be “too costly to ratepayers since it will come on line before it is needed and will contribute to an oversupply of capacity.” The Commission adopted TURN’s proposal to require departing load customers to pay the costs of these resources for ten years so that “ratepayers are not overburdened during the early years of the contract with stranded costs if all the power is not needed…. The Commission’s decision did not authorize SCE to reopen cost allocation of this resource in later years.

The Commission applied this limitation more generally in its 2004 adoption of the utilities’ Long-Term Procurement Plans, extending it prospectively to all “fossil-fueled

\(^{89}\) Joint Utilities Direct Testimony at 5-8 – 5-10.
\(^{90}\) D.03-12-059 at 35, Finding of Fact 22.
\(^{91}\) Id. at 32.
resources acquired by the utilities either directly or through contract.” 92 It made clear that the limitation would apply to “utility-owned generation acquired as a result of the procurement process, commencing once the resource begins commercial operation.” 93 In the next paragraph, the Commission contemplated greater flexibility for commitments under PPAs. It stated:

As several parties have noted, limiting commitments for new resources to only ten years may still increase costs for captive ratepayers due to the need for the project developer to seek accelerated cost recovery for their investments rather than amortizing these investments over a longer period. 94

In describing these circumstances, the Commission said that it would “allow the utilities the opportunity to justify in their applications, on a case-by-case basis, the desirability of adopting a cost recovery period of longer than ten years.” At the same time, it made clear that a longer term stranded cost recovery would apply to renewable resources. 95

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

[T]he utilities can, over time, adjust their load forecasts and resource portfolios to mitigate the effects of DA, CCA, and any large municipalizations on bundled service customer indifference. By the end of the 10-year period, we assume that the utilities would be able to make substantial progress in eliminating such effects for customers who cease taking bundled service during that period. 96

It further observed that the resources also may become more economic over time, suggesting that it would be to ratepayers benefit to hold those resources to lower total portfolio costs at a later date. It provided, however, that if the utilities “believe a cost

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92 D.04-12-048 at 61.
93 Id.
94 Id.
95 Id. at 63.
96 D.08-09-012 at 54-55.
recovery period extension is appropriate and necessary for specific non-RPS resources, they can make such requests . . . "97

The utilities have provided no data on the impact of this proposal, nor do they even identify the plants at issue. Instead, they offer only generic arguments. First, "a market does not exist that would provide additional revenues to compensate for the full capacity value of post-2002 UOG resources."98 Second, "the level of potential load departure that the Joint Utilities face today is substantially higher than any load departure contemplated at the time the 20-year limit was adopted."99 In essence, they argue that they have not been able to anticipate or forecast load loss over the past 15 years, an exercise the Commission has repeatedly required the utilities to do.

Neither argument supports the dramatic change in rules the Joint Utilities request.

As an initial matter, the 2003 and 2004 decisions contemplated modifying the 10-year rule in the applications for resources, on a case-by-case basis. They did not contemplate modifying the 10-year rule after resources were approved. Similarly, the 2008 decision referenced back to the earlier decisions, providing for recovery period extension "for specific non-RPS resources . . . under the provisions of D.04-12-048."

Changing the rules of the game entirely, many years after the resources were built, would fail to provide notice of the implications of departure, particularly for those customers who have already departed utility service.

Looking beyond the questions of timing and notice, the absence of a capacity market cannot justify the significant modifications the utilities request. There has been

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97 Id. at 55.
98 Joint Utilities Direct Testimony at 5-9.
99 Id. at 5-10.
100 D.08-09-012 at 55.
no transparent capacity market for the past 15 years – nothing has changed, yet the Joint Utilities have waited until now to raise this question. Moreover, the Commission’s decisions were not based solely on the expectation that a capacity market would develop; the Commission also appropriately considered the utilities’ obligations to reasonably forecast and plan for their load and the long-term value profile of UOG as they depreciate. As discussed in CalCCA’s opening testimony, the Joint Utilities have only in the last few years made strides to improve their departing load forecasting.\textsuperscript{101}

The utilities have provided no reasonable basis or detail to support lifting the long-standing 10-year limitation on recovery of post-2002 fossil resources, and their proposal should be rejected.

\textsuperscript{101} CalCCA Testimony at 3-12.
CALIFORNIA COMMUNITY CHOICE ASSOCIATION
REBUTTAL TESTIMONY

CHAPTER 6

FORECASTING COST RESPONSIBILITY FOR FUTURE PERIODS
(Common Outline §VI)
CALIFORNIA COMMUNITY CHOICE ASSOCIATION
REBUTTAL TESTIMONY

CHAPTER 7

OTHER ISSUES
(Common Outline §VII)
I. THE JOINT UTILITIES PROVIDE NO REASONABLE BASIS TO TREAT CERTAIN RPS COSTS DIFFERENTLY FROM OTHER RPS COSTS UNDER THE PCIA

The Joint Utilities propose that costs incurred for procurement mandated by the Legislature or Commission without regard to a utility’s load share should be recovered from all “benefitting” customers. The charge would be implemented on all departing load customers, regardless of the vintage of their departure. The Joint Utilities identify five programs that they argue are included in this category: the Renewable Auction Mechanism, the Renewable Market Adjusting Tariff, Bioenergy Market Adjusting Tariff, Non-CHP PURPA, and the AB 1969 Feed-in Tariff. CalCCA opposes this proposal; the costs are already included in the PCIA on a vintage basis, and the Joint Utilities have provided no basis to justify their different treatment.

The RAM, ReMAT (which replaced the AB 1969 FiT) and the BioMAT programs are not incremental to the utilities’ RPS programs. They are simply mandated tools for the Joint Utilities to use in procuring RPS-eligible resources to meet their RPS compliance obligations. Their RPS obligations remain the same as the obligations imposed on CCAs and ESPs.

The programs are targeted at different types of resources. Three of the programs rely on a type of competitive solicitation:

- The RAM is the mechanism for procurement of RPS-eligible resources under 20 MW.
- ReMAT is the mechanism for procurement of RPS-eligible resources up to 3 MW.

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102 Joint Utilities Direct Testimony at 7-3 – 7-6.
103 Id., Table 7-1.
The BioMAT program is the mechanism for procurement of RPS-eligible bioenergy resources.

Each kWh procured under these programs can be used by the utility to comply with its RPS obligation. While PURPA is not a State-mandated tool and is not implemented through competitive solicitation, non-CHP PURPA contracts executed on or after January 1, 2015 are RPS-eligible. While costs may be higher, they are no different than procurement of an RPS resource under a different type of RPS solicitation.

Consequently, resources procured using these mechanisms should be included in the PCIA in the same way other RPS resources are included – on a vintaged basis.

The fact that these programs are implemented with specific targets, irrespective of load, does not change this analysis. The Commission and the Legislature have legal authority to dictate how the utilities meet their RPS requirements, and they have exercised this authority in mandating procurement under RAM, ReMAT and BioMAT.

While the Legislature also imposed the RPS requirements on CCAs, it did not elect to direct how the RPS compliance obligation should be met. Instead, the Legislature provided in §366.2(a)(5): “A community choice aggregator shall be solely responsible for all generation procurement activities on behalf of the community choice aggregator’s customers, except where other generation procurement arrangements are expressly authorized by statute.” Consistent with this directive, the government authority under which a CCA is organized has authority to direct CCA RPS procurement in the way that best suits the opportunities available to the CCA that fit within the portfolio and meet the expectations of the CCA’s customers.

105 Cal. Pub. Util. Code §399.21(a)(5). The 2017 RPS Annual Report shows only one such project for a total of 1 MW. Pre-2002 vintage PURPA contracts are a part of the CTC. See RPS Annual Report at 18.
Finally, the Joint Utilities’ proposal to ignore departure vintage runs contrary to California’s practice of ensuring notice of prospective cost responsibility to departing load customers. The first departing load charge, the CTC, was implemented for departures after customers should have been on constructive notice due to a Commission decision contemplating such charges. Subsequent departing load charges followed the practice of grandfathering customers that had departed prior to notice of the potential for cost responsibility.

The CDWR Bond Charge and CDWR Power Charge for some customers were made effective prospectively for customers departing after January 17, 2001 – the date on which CDWR began purchasing power on behalf of the utilities’ customers pursuant to a proclamation of emergency by Governor Davis.

The CDWR Power Charge for DA customers likewise was imposed to align with CDWR procurement, imposing the charge on customer departing on or after February 1, 2001.

The departing load obligation for SCE’s Mountainview facility and other post-2002 utility generation was known at the time the generation was procured.

Most recently, SB 350 established a nonbypassable charge obligation for renewable procurement resulting from the Commission’s implementation of 454.51(a).

To change the rules in the middle of the game, imposing these costs without any notice of the obligations for these charges when a customer departs, would fail to provide reasonable notice. Taking this approach would thus materially impair opportunities for future CCA development, as CCAs would have no capability of predicting the nature and the magnitude of potential departing load charges.

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106 Cal. Pub. Util. Code §368(c) (grandfathered customers departing the system prior to December 20, 1995, the date on which the Commission issued its Preferred Policy restructuring decision, D.95-12-063, which contemplated departing load charges).

107 See, e.g., D.03-04-030 at n.4 (“On January 17, 2001, Governor Davis issued a Proclamation that a ‘state of emergency’ existed within California resulting from dramatic wholesale electricity price increases.”).

108 See, e.g., D.03-12-058 and D.08-09-012.
Vintaging is also critical from a policy perspective. Particularly as utility load declines, California has an interest in ensuring that all LSEs undertake programs that further State climate change policy goals. Imposing the costs of specific utility programs (e.g., ReMAT) aimed at RPS compliance equally on all CCA and departing load customers, regardless of their departure vintage, impairs the CCAs’ ability to contribute to achievement of State climate goals in the ways that most benefit their communities.

CCAs have begun to implement targeted programs tailored to their communities’ needs to meet their RPS compliance obligations – programs whose costs are not spread to bundled customers. For example, Sonoma Clean Power implemented its ProFit feed-in tariff (100% RPS) to procure local RPS-eligible resources of 1 MW or less for contract terms of 10 or 20 years.\(^\text{109}\) Likewise, SCP’s EverGreen program provides customers 100% geothermal power sourced from within Sonoma and Mendocino counties.\(^\text{110}\) Small, specialized resources to meet the needs of these programs typically carry a premium over other RPS compliance resources. Additionally, MCE recently brought online its MCE Solar One project, which is a 60 acre, 10.5 MW solar project in Richmond, CA capable of providing enough renewable electricity to approximately 3,900 MCE customers annually.\(^\text{111}\) This project was partially funded by MCE’s Deep Green 100% renewable energy customers who pay a penny per kilowatt hour premium for wind and solar generation in California. Half of this premium is used to fund local solar projects like MCE Solar One. The fact that many CCA contracts for RPS

\(^{109}\) [https://sonomacleanpower.org/profit-program/](https://sonomacleanpower.org/profit-program/).

\(^{110}\) [https://sonomacleanpower.org/your-options/evergreen/](https://sonomacleanpower.org/your-options/evergreen/).

resources secured over the past several years are now “above-market” relative to current conditions also argues for sustaining a Vintaging process, if only to ensure that early CCAs who have entered into relatively high-priced PPA for RPS sources are not overly penalized for doing so. The fact that those CCA customers have also paid down their financial obligations for prior IOU contracts should be honored as well.

For these reasons, CalCCA opposes adoption of the Joint Utilities’ proposal to make certain RPS program costs subject to a departing load charge that does not distinguish obligations by a customer’s departure vintage.

II. PREPAYMENT

CalCCA proposed an option for CCAs to pre-pay part or all of a customer’s forward PCIA obligation.\textsuperscript{112} AREM/DACC, likewise, propose that departing or departed customers be allowed to pay their future PCIA obligation via a single lump-sum payment or payments levelized over a three- or five-year term.\textsuperscript{113} The proposals by CalCCA and AREM/DACC share common ground and, subject to limited modifications, CalCCA generally supports the AREM/DACC proposal as a reasonable alternative. ORA, however, raises concerns regarding prepayment options. We explain below why these concerns are misplaced.

A. AREM/DACC and CalCCA Prepayment Options Share Common Ground

CalCCA generally supports the direction of AREM/DACC in proposing a prepayment option. AREM/DACC are correct that “[the PCIA] can be volatile and …

\textsuperscript{112} CalCCA Testimony, Chapter 7 at 7-1 – 7-7.
\textsuperscript{113} AREM/DACC Direct Testimony at 22. While AREM/DACC offer three options, this rebuttal addresses the first two – lump sum and installment based prepayment – which CalCCA sees simply as the same prepayment option with different payment terms.
options to better manage that aspect of the DA customers’ power costs are needed.”\textsuperscript{114} AR\textsuperscript{e}M/DACC also correctly contend that a prepayment of above-market obligations is a proven option to ensure certainty, reduce risk, and mitigate the need for on-going regulatory intervention. They also propose that the utilities prepare 15-year forecasts of portfolio costs and offer flexible terms for prepayment, both lump-sum and installment options. Finally, AR\textsuperscript{e}M/DACC oppose the use of a true-up because a true-up “would defeat the main purpose of the option: to reduce the customer’s energy cost uncertainty.”\textsuperscript{115} CalCCA and AR\textsuperscript{e}M/DACC share common ground on these points.

The AR\textsuperscript{e}M/DACC proposal is intended primarily for DA customers, although the parties recognize that “something analogous may be appropriate for CC\textsuperscript{a}S or their customers.”\textsuperscript{116} CalCCA agrees that an analogous approach could meet the objectives of CC\textsuperscript{a}S in extinguishing their customers’ forward uneconomic cost obligations, with three changes: the application of the discount factor should be clarified, obligations beyond Year 15 should be addressed and longer term CCA departing load forecasts should be used in the calculation of forward obligations.

**Discount Factor.** AR\textsuperscript{e}M/DACC presents the calculation as:\textsuperscript{117}

\[
\text{Present Value} = (PCIA_{yr1})(Load) + (PCIA_{yr2})(Load)(1+\text{Discount Rate})^2 + \ldots + (PCIA_{yn})(Load)(1+\text{Discount Rate})^n
\]

CalCCA believes that a clarification of this formula is in order: that future PCIA obligations should be *discounted* at the discount rate, not *compounded* by the discount rate, as the formula above appears to show. On that basis, CalCCA believes that the correct formula should be expressed as follows:

\textsuperscript{114} AR\textsuperscript{e}M/DACC Direct Testimony at 21:18-20.
\textsuperscript{115} AR\textsuperscript{e}M/DACC Direct Testimony at 25.
\textsuperscript{116} Id. at 24:8-10.
\textsuperscript{117} Id. at 22:14-20.
Present Value = \( \frac{(PCIA_{yr1})(Load)}{(1+Discount \ Rate)} + \frac{(PCIA_{yr2})(Load)}{(1+Discount \ Rate)^2} + \ldots + \frac{(PCIA_{yrn})(Load)}{(1+Discount \ Rate)^n} \)

**Terminal Value.** AReM/DACC propose to facilitate forecasts and payments for 15 years, after which any remaining balance would be credited towards the ERRA. For payment purposes, it is important to recognize the time value of money embedded in future obligations. That is, a $100 payment due at Year 16 is larger in present value terms than a $100 payment due at Year 30. Because many stranded-costs are for obligations which persist decades into the future, accurately discounting those future payment streams is necessary. If the utility forecast is limited to 15 years, it would be possible to add a terminal value at Year 16 to account for the additional discounted obligations for Years 16 onwards.

**Incorporate CCA/ESP Load Forecasts.** AReM/DACC propose to calculate the PCIA one-time payment using the “average metered load of the customer over the three-year period prior to the time of the customer’s election to make prepayment.”\(^{118}\) A DA’s customers load is likely to be relatively static compared with a CCA’s load, and coupling this three-year average with changes in forecasted load due to expansion or return of customers to bundled service is a reasonable approach. With continuing CCA growth and expansion of existing CCA service territories, it may be necessary to develop a more forward looking CCA departure forecast.

**B. ORA’s Concerns Regarding Calculation and CCA Default Can Be Reasonably Addressed**

ORA raises two central concerns regarding lump-sum buyouts of departed customers’ ongoing liabilities: 1) how to calculate the lump-sum buyout amount, and, 2) how contract rights and obligations would be shared between LSEs after this

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\(^{118}\) AReM/DACC Direct Testimony at 23.
Fortunately, there are many examples to draw from for calculating the lump-sum buyout amount. In California, nine Californian entities (six cities and three irrigation districts) have agreed upon and paid a lump-sum to alleviate on-going departing load liabilities to the IOU. This may be done in a bilateral (e.g. negotiated basis), or in accordance with the Municipal Departing Load tariffs of each IOU.\(^\text{120}\) In addition, as noted in CalCCA’s opening testimony, customers in Washington State and Nevada have recently come to agreed-upon lump-sum payments of their future obligations.\(^\text{121}\) In Washington, the departing customer and incumbent utility calculated the payment amount and jointly filed for approval with the Washington Utilities and Transportation Commission. In Nevada, Public Utilities Commission staff worked to develop and approve the calculation methodology for use by departing customers.

ORA’s concern regarding the nature of the rights in the event of CCA default appears to misunderstand the nature of prepayment proposals. ORA asserts that “it is unclear what obligations and rights departing load providers and IOUs would have relative to these contracts if a CCA or ESP went out of business or its customers migrated back to bundled service.” It also suggests that “(o)ne option might be that the CCA or ESP would refund all or a portion of the portfolio it purchased.”\(^\text{122}\) ORA is conflating two alternatives to the PCIA: prepayment of the financial obligation and outright purchase of, or rights to, a specific utility contract. As discussed in CalCCA’s opening testimony, prepayment is not necessarily for the purchase of a portfolio or portion thereof, but more likely a prepayment of the future stream of obligations for the

\(^{119}\) ORA Direct Testimony at 4:13-25.
\(^{120}\) PG&E Schedule E-NMDL, SCE Schedule NMDL, and SDG&E Schedules CGDL-CRS and E-DEPART.
\(^{121}\) CalCCA Testimony, Chapter 7 at 7-3 – 7-4.
\(^{122}\) ORA Direct Testimony at 4:14-23.
uneconomic costs of the portfolio. While CalCCA’s proposal contemplates access to utility resources by other LSEs, access would occur through bilateral purchase/sales negotiations with or auctions by the utility, not in the context of prepayment.

If there is a concern about risk of CCA default in the context of prepayment, the risk falls to the CCA, particularly if no refund provisions are included as a part of the agreement supporting prepayment. Having made an upfront, lump-sum payment for future uneconomic cost liability, the CCA’s customers could be returned to the utility portfolio unburdened by ongoing obligations for uneconomic portfolio costs.

III. THERE IS NO REASONABLE BASIS FOR DISTINGUISHING PRE-2009 VINTAGE DA CUSTOMERS FROM ANY OTHER DEPARTING LOAD CUSTOMER WITH RESPECT TO OBLIGATIONS FOR LEGACY UOG COSTS

AReM/DACC propose to “memorialize” the permanent exemption of Legacy UOG from the PCIA for pre-2009 vintage.\(^{123}\) They explain that “in 2016, PG&E ceased collecting a PCIA from pre-2009 vintage DA customers.”\(^{124}\) They further observe in support for their proposal that SDG&E “has no power generating resources in its pre-2009 Vintage” and that SCE has stipulated that the only SCE Legacy UOG costs that will be imposed on pre-2009 vintage DA customers are those associated with the San Onofre Nuclear Generating Station.\(^ {125}\)

Based on the Joint Utilities’ calculation, substantial Legacy UOG costs remain in the calculation of PCIA costs charged to post-2009 vintage customers, including CCA customers, for PG&E and, contrary to AReM/DACC’s contention, for SCE.\(^ {126}\) There is

\(^{123}\) AReM/DACC Direct Testimony at 33.

\(^{124}\) Id. at 32:5-6.

\(^{125}\) Id. at 32.

\(^{126}\) CalCCA estimates that PG&E’s Legacy UOG contribution to the PCIA is $585 million. See CalCCA Direct Testimony 2B-20 – 2B-21. It estimates SCE’s 2018 Legacy UOG PCIA contribution to be $270 million.
no reasonable basis to treat pre-2009 vintage customers differently than post-2009 vintage customers. These costs were previously assigned or attributed to pre-2009 DA customers, and they are not costs caused by the departure of CCA customers.

The inclusion of Legacy UOG costs in the PCIA has its roots firmly in DA history and dynamics. They should not have been included in the PCIA from the outset in 2002 and, by statute, should never have been included in the costs attributable to CCAs. Despite these circumstances, CalCCA has not proposed an exemption from these costs in its opening testimony. That said, CalCCA is not opposed to removal of these costs. If the Commission determines that Legacy UOG costs should be removed from pre-2009 customers’ PCIA, similar treatment should be accorded CCA customers. It would be discriminatory not to exempt all DA and CCA customers from Legacy UOG costs in the PCIA.\(^\text{127}\)

A. Legacy UOG Costs Should Never Have Been Included in the PCIA

The Legislature enacted Assembly Bill 1890 in 1996, which contemplated the possibility of utility divestiture of generation assets\(^\text{128}\) and anticipated a full transition to a competitive market by 2002.\(^\text{129}\) 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,

\(^{127}\) As the Commission has previously stated, a particular rate treatment is considered unlawful discrimination if the treatment draws “an unfair line” or strikes “an unfair balance” between similarly situated customers and there is no rational basis for the different treatment. See, e.g., D.11-03-031 at 2 (citing D.06-04-041 at 5-6).

\(^{128}\) See Pub. Util. Code §367(b). The Commission later found that divestiture was the “only structural option which will completely eliminate the utility’s ability to engage in improper cross-subsidization.” D.95-12-063 at 193.

\(^{129}\) 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…..).
regardless of supplier.\textsuperscript{130} 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{131} It concluded: “With the exception of CTC arising from existing contracts, no further accumulation of CTC will be allowed after 2003 and collection will be completed by 2005.”\textsuperscript{132}

While many changes have unfolded in California’s electricity market since 1996, allowing the utility to continue to recover the costs of any Legacy UOG from any customer cannot be justified. The utilities were given clear notice that California was transitioning and had a chance at that time to address uneconomic Legacy UOG.\textsuperscript{133} It is even more difficult to justify in light of Legislative directives in AB 117, which limited the scope of stranded cost recovery from CCA customers to “purchase contract costs.”

AB 117 requires the Commission to adopt a “cost-recovery mechanism to be imposed on the community choice aggregator pursuant to subdivisions (d), (e), and (f) that shall be paid by the customers of the community choice aggregator to prevent shifting of costs.”\textsuperscript{134} The statute thus clearly defines the scope of the costs that must be paid by CCA customers to avoid a cost shift from departing CCA customers to bundled customers: the CDWR bond component,\textsuperscript{135} the CDWR power charge component,\textsuperscript{136}

\begin{footnotesize}
\begin{enumerate}
\item \textit{Id.} at 119.
\item \textit{Id.} (emphasis supplied).
\item See, e.g., D.95-12-063, 64 CPUC 2d, 1, 49 (“Our proposal contemplates a five-year transition period during which some utility generation assets will remain under the ownership of the utility and our regulations, while others will undergo a market valuation process and possible a transfer of ownership.”); Cal. Pub, Util. Code §367(b) and §390(c).
\item \textit{Id.} §366.2(e)(2).
\end{enumerate}
\end{footnotesize}
undercollections related to “electricity purchases” and “electricity purchase contract costs.” Nothing in the statute provides that CCA customers pay for any UOG costs to avoid a cost shift, beyond the costs collected through the CTC established in AB 1890.

Why did the statute exclude UOG costs from the scope of CCA customer responsibility? Nothing in the Committee or Floor analyses of AB 117 illuminates this question. The answer may lie in the contemporaneous dynamics arising from the DA CRS discussions summarized in D.02-11-022. The decision explains that the Commission deferred the DA suspension under AB 1X in exchange for DA customers paying a nonbypassable charge to cover the costs of CDWR long-term procurement. In comments leading up to D.02-11-022, CLECA further argued that if DA customers took on the above-market costs of CDWR contracts, the costs should be offset by the benefits of lower cost Legacy UOG. Residential ratepayers disagreed:

ORA objects to CLECA’s indifference approach, arguing that the cost of URG resources are “off limits” to DA customers, but are dedicated to service of bundled customers. The Commission ultimately adopted CLECA’s recommendation in D.02-11-022, imposing the above-market costs of CDWR contracts on DA customers, balanced by including lower cost Legacy UOG in the PCIA and an extension of the implementation date for the AB 1X suspension of DA. The Commission reexamined the issue of including utility generation in departing load charges in D.08-09-012. As an important factual predicate, at the time D.02-11-022 and D.08-09-012 were issued, Legacy UOG

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137 Id. §366.2(f)(1).
138 Id. §366.2(f)(2).
139 Committee analyses are found at http://www.leginfo.ca.gov/cgi-bin/postquery?bill_number=ab_117&sess=0102&house=B&author=migden.
140 D.02-11-022 at 23.
141 Id.
142 See generally D.08-09-012 at 49-52.
were assumed to be “lower cost” than other resources, and therefore would have a
mitigating or netting effect on overall departing load charges.\textsuperscript{143} This fact was
acknowledged by PG&E, which asserted that “departing customers should not receive the benefits of existing generation after they leave bundled service.”\textsuperscript{144} Based on the assumption that UOG would lower the overall departing load charge, the Commission adopted a total portfolio approach that not only considered “cost-shifting” from new resources but also allowed UOG resources to be “netted” against this cost-shift.\textsuperscript{145}

While Legislative history does not shed light on why the CCA cost responsibility was limited to “purchase contract costs,” the DA dynamics that occurred at the Commission in 2002 may provide a reasonable explanation: residential ratepayer representatives did not want to share the benefits of the lower-cost Legacy UOG with CCA customers. CCA customers have had only limited, if any, benefit from including Legacy UOG in the calculation. Exhibit 7-A shows that since 2011, PG&E’s Legacy UOG has contributed to uneconomic costs and have been recovered through the PCIA. Thus neither regulatory history nor AB 117 provides a basis for including Legacy UOG in the PCIA imposed on CCA customers.

\textsuperscript{143} See, e.g., D.08-09-012 at 49; n.52 (emphasis added) ("For purposes of this decision, ‘pre-restructuring resources’ refers to those current IOU resources that existed prior to March 31, 1998 and are not subject to ongoing CTC treatment. These resources consist principally of the IOUs’ retained generation (i.e., hydro, coal and nuclear plants). Power from these resources tends to be cheaper when compared to the costs related to ongoing CTC, the DWR contracts and new generation.").

\textsuperscript{144} D.08-09-012 at 49.

\textsuperscript{145} See D.08-09-012 at 51 (citing in part D.02-11-022 at 25).
B. Excluding Legacy UOG Costs for Pre-2009 Departing Load Customers While Continuing to Impose These Costs on CCAs is Discriminatory

Effective January 1, 2016, PG&E stopped including all Legacy UOG costs in the PCIA for pre-2009 vintage customers. SCE has proposed to remove Legacy UOG costs in the PCIA for pre-2009 vintage customers. As described by SCE, “[u]nder the Settlement Agreement … pre-2002 Legacy UOG resource costs and their associated forecast generation output would be excluded from the PCIA calculation.” Notably, since the first CCA did not launch until 2010, and DA is no longer open to new enrollment, these actions effectively discontinue Legacy UOG recovery from DA customers while continuing recovery from CCA customers.

In light of these developments, it is reasonable to examine in this proceeding whether or not UOG costs should be excluded from the PCIA calculation for all departing load customers – not just pre-2009 departing load customers.

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146 In fact, as of January 1, 2016 PG&E stopped applying the PCIA entirely to pre-2009 vintage customers. An associated issue (retirement of PG&E’s negative indifference balance for pre-2009 customers) was deferred. (See D.15-12-022 at 23; Ordering Paragraph 5.)

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

148 PCIA Settlement Motion at 4, n.8. The sole exception to this proposal relates to SONGS; however, under a separate settlement before the Commission in I.12-10-013 et al., SCE proposed to eliminate SONGS cost-recovery for purposes of the PCIA on or about December 19, 2017. See Joint Motion for Adoption of Settlement Agreement, dated January 30, 2018, at 5 (I.12-10-013 et al.).
C. CalCCA Remains Willing to Continue to Pay Legacy UOG Costs
Provided the Commission Recognizes the GHG-free Value of Nuclear
and Hydro Assets and Makes these Resources Available to the
Market

While observing the discriminatory effect of memorializing an exemption for pre-
2009 vintage DA customers in opening testimony, CalCCA has not yet proposed an
exemption for CCA customers from the Legacy UOG costs.\textsuperscript{149} CalCCA agreed to
continue to include these resources in the PCIA calculation if the Legacy UOG –
primarily large hydro and other GHG-free resources – is securitized and the
Commission: (a) adopts a PCIA benchmark value that reflects the GHG-free value of
nuclear and hydro facilities and (b) makes these GHG-free resources available
generally to the market. While CalCCA believes that excluding Legacy UOG from the
PCIA entirely is the most legally defensible outcome, CalCCA is willing to explore
inclusion of these resources in the PCIA if these moderating measures are also
accepted, and if Legacy UOG is borne by all departing customers and bundled

customers.\textsuperscript{150}

\textsuperscript{149} CalCCA Testimony at 2-19 – 2-21.
\textsuperscript{150} If, however, the Commission chooses to treat pre-2009 DA customers differently than
CCA customers, the Commission must also ensure that any exemptions provided to pre-2009
DA customers be excluded from the PCIA calculations for CCA customers, since they are not
“attributable” to CCA departing load.
### EXHIBIT 7-A

**PG&E Legacy UOG Costs (Nuclear and Hydro)**

*Historical Comparison to PCIA Benchmark Values*

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<tr>
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<tbody>
<tr>
<td>Brown Power Benchmark ($/MWh)</td>
<td>$ 53.46</td>
<td>$ 36.02</td>
<td>$ 32.66</td>
<td>$ 38.90</td>
<td>$ 39.05</td>
<td>$ 41.25</td>
<td>$ 32.90</td>
<td>$ 35.22</td>
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<td>RA Benchmark ($/MWh)</td>
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<td>$ 4.00</td>
<td>$ 4.00</td>
<td>$ 9.31</td>
<td>$ 11.03</td>
<td>$ 10.96</td>
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<td>Total PCIA Benchmark ($/MWh)</td>
<td>$ 57.46</td>
<td>$ 40.02</td>
<td>$ 36.66</td>
<td>$ 48.21</td>
<td>$ 50.08</td>
<td>$ 52.21</td>
<td>$ 45.53</td>
<td>$ 47.03</td>
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<td>$46.90</td>
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<tr>
<td>Average Cost of Legacy UOG ($/MWh)</td>
<td>$ 42.79</td>
<td>$ 40.73</td>
<td>$ 45.67</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>$53.81</td>
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<tr>
<td>Legacy UOG Cost as % of PCIA Benchmark</td>
<td>74%</td>
<td>102%</td>
<td>125%</td>
<td>107%</td>
<td>108%</td>
<td>107%</td>
<td>137%</td>
<td>142%</td>
<td>143%</td>
<td>115%</td>
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<tr>
<td>Uneconomic Legacy UOG Costs in PCIA ($Millions)</td>
<td>($429)</td>
<td>$21</td>
<td>$264</td>
<td>$94</td>
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