BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment

R.17-06-026
(Filed June 29, 2017)

OPENING BRIEF OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION

PUBLIC VERSION

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TABLE OF CONTENTS

I. INTRODUCTION AND EXECUTIVE SUMMARY (COMMON OUTLINE §§I & II) ................................................................. 1
   A. The Commission Plays a Central Statutory Role in Realizing the Legislature’s Vision for a Partnership Among the State, Joint Utilities and Other LSEs to Implement State Policy Goals ................................ 5
      1. The Commission Must Prevent Cost Shifts Between Bundled and Departing Load Customers ................................................. 5
      2. The Commission Must Preserve CCAs’ Rights to Be Solely Responsible for Procurement on Behalf of Their Customers .......... 8
      3. The Commission Must Prevent the Utilities from Using Their Dominance to Undermine CCA Development or Operation and Ensure Fair Competition between the Joint Utilities and Other LSEs .......................................................... 9
      4. The Commission Must Ensure Just and Reasonable Rates .................. 10
   B. CalCCA Proposes a Phased Transition Plan to Allocate Uneconomic Costs and Accommodate Future CCA Growth Consistent with the Commission’s Statutory Obligations ........................................... 10

II. BACKGROUND (COMMON OUTLINE §I) ............................................................................................................. 13

III. THE LEGISLATURE HAS CREATED A ROADMAP FOR ASSESSING AND REFINING THE CURRENT METHODOLOGY (COMMON OUTLINE §I) ........................................................................... 18
   A. The Legislature Has Specifically Identified the Procurement Costs that Must Be Allocated to Prevent Cost Shifts ....................... 18
   B. The Legislature Granted CCAs the Sole Right to Procure Resources on Behalf of Their Customers, Subject Only to Exceptions Specified by Statute ........................................................................... 21

IV. THE CURRENT METHODOLOGY SHIFTS COSTS FROM BUNDLED CUSTOMERS TO DEPARTING LOAD CUSTOMERS (COMMON OUTLINE §III) .............................................................................. 23

V. THE SCOPE OF RESOURCE COSTS THAT MAY BE ALLOCATED THROUGH THE PCIA IS LIMITED BY STATUTE AND PRIOR COMMISSION DECISIONS (COMMON OUTLINE §IV) .............. 29
A. Legacy Utility Owned Generation Costs Do Not Fall Within the Scope of Costs That Can Be Allocated to CCA Departing Load Customers

1. State Law Does Not Require CCA Departing Load Customers to Pay for Legacy UOG Costs

2. The Inclusion of Legacy UOG Costs in the PCIA Was Unrelated to and Did Not Materially Benefit CCA Departing Load

3. Mandating That CCA Customers Continue to Bear Legacy UOG Cost Responsibility While Exempting Pre-2009 DA Customers Would Unlawfully Discriminate Against CCA Customers

4. The Recovery of Legacy UOG Costs Through the PCIA Should Be Discontinued

B. Post-2002 Utility Owned Generation Costs

1. Nothing Has Changed to Warrant Removal of the 10-Year Limitation on Recovery of Post-2002 UOG Costs Through the PCIA

2. Inclusion of Post-2002 Utility Owned Generation Costs in the CCA PCIA is Limited by Statute

VI. LONG-TERM RESOURCES SHOULD BE VALUED USING LONG-TERM VALUATION MEASURES (COMMON OUTLINE §V)

A. The Commission Has a Depth of Experience in Portfolio Valuation

B. Portfolio Valuation to Determine Uneconomic Costs Must Recognize All Valuable Products and Attributes

C. Value Measures Used to Determine Uneconomic Costs Must Reflect the Long-Term Characteristics and Value of the Utility Portfolio

VII. CALCCA RECOMMENDS ADOPTING A CORRECTED BENCHMARK METHODOLOGY TO DETERMINE THE PCIA UNTIL A MORE DURABLE, COMPREHENSIVE SOLUTION CAN BE IMPLEMENTED BASED ON VOLUNTARY, MARKET-BASED RESOURCE REDISTRIBUTION (COMMON OUTLINE §VI)

A. Correct the Current Methodology as a Bridge to a Longer Term Durable Solution
1. Align Capacity Benchmark with Long-Term Capacity Value ..........53

2. Adopt a Benchmark to Reflect Ancillary Services Value ..........62

3. Adopt a Benchmark to Reflect the Market-Recognized Premium for GHG-Free Energy ..........63

4. Correct the Green Adder by Removing the Outdated Department of Energy Benchmark Component ..........67

B. Adopt a Voluntary, Market-Based Solution That Will Reduce Utility Portfolio Size and Redistribute Resources, While Producing More Reliable Value Measures ..........69

1. CalCCA’s Proposed Staggered Portfolio Auction is a Voluntary, Market-Based Portfolio Allocation Mechanism to Redistribute Utility Supply ..........70

2. The SPA Provides More Reliable Valuation Measures for the Utilities’ Portfolios ..........72

3. The SPA Provides the Commission with the Ability to Structure the Details of the Auction Process to Ensure Efficiency and Optimal Outcomes ..........73

4. The SPA Provides the “Sales Receipt” the Joint Utilities Claim to Need to Avoid Cost Shifts and is the Only Recommended Alternative Where the Receipt Matches the Product that the CCAs are Paying for Through the PCIA ..........75

5. A Residual Portfolio May Remain and Will Require Further Consideration ..........75

6. The SPA Complements the Commission’s Integrated Resource Planning Process and Support Environmental Policy Goals ..........76

7. The SPA Can Reasonably Be Implemented by January 1, 2020 ..........78

C. CalCCA’s Proposed Comprehensive Solution Aligns with the Guiding Principles for this Rulemaking ..........78

VIII. THE COMMISSION SHOULD REJECT THE JOINT UTILITIES’ PROPOSED GAM/PMM. (COMMON OUTLINE §VI) ..........81

A. The GAM Is Unlawful ..........81
B. The GAM/PMM Unreasonably Sustains Utility Market Dominance as Bundled Load Declines ................................................................. 86

C. The GAM/PMM Devalues Portfolio Resources .................................................... 88
   1. GAM Allocations of RECs Reduce or Eliminate the “Bundled” and “Long-Term” Value of the Underlying RPS Resources .......................................................... 88
   2. The GAM/PMM Fails to Preserve and Convey All Value of the Portfolio Resources ................................................................. 92

D. The GAM/PMM Is Not a Long-Term Solution Yet is Too Incomplete and Complex to Serve as an Effective Interim Solution ......................... 94

IX. IMPROVEMENTS IN PORTFOLIO MANAGEMENT PRACTICES SHOULD BE ADOPTED TO REDUCE AND PREVENT FURTHER ACCUMULATION OF UNECONOMIC PORTFOLIO COSTS (COMMON OUTLINE §VII) ................................................................................................. 97
   A. The Commission Should Direct the Joint Utilities to Modify Their Forecasting Practices to Better Account for Departing Load ....................... 97
   B. The Commission Should Direct the Joint Utilities to Improve Portfolio Management Practices ............................................................ 103
      1. Require the Joint Utilities to Actively Manage Their Portfolios in Response to Departing Load ......................................................... 104
      2. Prohibit the Joint Utilities’ Practices Aimed to Protect Shareholders and Bundled Ratepayers at Departing Load Customers’ Expense ......................................................... 107
      3. Require the Joint Utilities to Optimize Sales from Their Portfolios to Capture the Full Value of the Resources for All Customers ................................................................. 112

X. THE COMMISSION SHOULD DIRECT THE UTILITIES TO USE THEIR BEST EFFORTS TO REDUCE PORTFOLIO COSTS USING SECURITIZATION OF UOG ASSETS AND CONTRACT BUYDOWN TRANSACTIONS (COMMON OUTLINE §VII) .............................................................................. 115
   A. Securitization is a Low-Cost Financing Tool That Has Been Used in the Utility Industry ................................................................. 117
   B. Securitization Reduces Portfolio Costs ............................................................... 120
C. Securitization of Utility Owned Generation Would Produce Substantial Cost Reductions for Bundled and Departing Load Customers ................................................................. 122

D. Voluntary Reverse RFO and Securitized Buydown of PCIA-Eligible PPAs Could Further Reduce Costs ........................................................................................................ 124

E. Limitations on the Utilities’ Ability to Employ Securitization Should Not Come into Play Under CalCCA’s Proposal .............................................................. 127

F. Securitization Examples .................................................................................................................. 128

XI. OTHER ISSUES (COMMON OUTLINE §VIII) ............................................................................. 133

A. The Commission Should Authorize Prepayment of Departing Load Cost Responsibility ........................................................................................................ 133

1. The Commission Has Previously Directed the Utilities to Permit California Publicly Owned Utilities to Prepay Departing Load Obligations ..................................................... 134

2. Commercial Customers Have Prepaid Bundled Service Obligations When Departing Utility Service ...................................................................................... 135

3. The Prepayment Calculation Could Rely on Values from the Staggered Portfolio Auction or as a Result of Bilateral Negotiation Subject to Commission Approval ........................................................................ 137

4. Prepayment Would Not Shift Costs Among Bundled and Departing Load Customers ........................................................................................................ 138

B. Caps, Floors and Sunsetting of Cost Responsibility ......................................................................... 139

1. The Commission Should Permit Parties to Request Rate Caps in Forecast ERRA Proceedings If Circumstances Warrant ......................................................... 139

2. The Commission Should Consider Establishing a Fixed Sunset Date or Trigger Event for Sunset of the PCIA ........................................................................ 141

C. The Commission Should Require the Utilities to Formalize the Approach Used in this Rulemaking for Long-Term PCIA Forecasting in ERRA Proceedings ......................................................... 142

D. The Commission Should Require the Joint Utilities to Separately Identify Uneconomic Costs as a Line Item on Bundled Customers’ Bills ......................................................................................... 144

XII. CONCLUSION .................................................................................................................. 146
# TABLE OF AUTHORITIES

## Statutes
- Cal. Water Code §80110 .......................................................................................................... 32

## Cases
- *Fields v. Eu* (1976) 18 Cal.3d 322, 332 .............................................................................. 32
- *Pacific Tel. & Tel. Co. v. Public Utilities Com.*, (1965) 62 Cal. 2d 634, 647 ................. 36, 41
- *Southern California Gas Co. v. Public Util. Com.* (1979) 24 Cal.3d 653 ...................... 41

## Legislation
- Assembly Bill 1 (Stats. 2001, 1st Ex. Session 2001, Ch. 4) ..................................................... 3, 14
- Assembly Bill 57 (Stats. 2002, Ch. 835) .............................................................................. 20
- Assembly Bill 117 (Stats. 2002, Ch. 838) ............................................................................ 3
- Assembly Bill 380 (Stats. 2005, Ch. 367) .......................................................................... 83
- Assembly Bill 1890 (Stats. 1996, Ch. 854) ........................................................................ 3, 13, 30, 43
- Senate Bill 790 (Stats. 2011, Ch. 599) .................................................................................. 9, 22, 86
- Senate Bill 1078 (Stats. 2001, Ch. 516) .............................................................................. 3, 19, 48

## CPUC Decisions
- D.95-12-063 ......................................................................................................................... 14, 30, 31
- D.01-09-060 ......................................................................................................................... 33
- D.02-03-055 ......................................................................................................................... 14, 33
- D.02-04-067 ......................................................................................................................... 14
- D.02-11-022 ......................................................................................................................... passim
- D.03-04-030 ......................................................................................................................... 97
- D.03-12-059 ......................................................................................................................... 37
# List of Acronyms

CalCCA Brief

<table>
<thead>
<tr>
<th>Acronym</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>A&amp;G</td>
<td>Administrative and General</td>
</tr>
<tr>
<td>AB</td>
<td>Assembly Bill</td>
</tr>
<tr>
<td>ABS</td>
<td>Asset Backed Securities</td>
</tr>
<tr>
<td>ACC</td>
<td>Avoided Cost Calculator</td>
</tr>
<tr>
<td>ALJ</td>
<td>Administrative Law Judge</td>
</tr>
<tr>
<td>AReM/DACC</td>
<td>Alliance for Retail Energy Markets, Direct Access Customer Coalition</td>
</tr>
<tr>
<td>AS</td>
<td>Ancillary Services</td>
</tr>
<tr>
<td>CAISO</td>
<td>California Independent System Operator</td>
</tr>
<tr>
<td>CalCCA</td>
<td>California Community Choice Association</td>
</tr>
<tr>
<td>CAM</td>
<td>Cost Allocation Mechanism</td>
</tr>
<tr>
<td>CCA</td>
<td>Community Choice Aggregation</td>
</tr>
<tr>
<td>CDWR</td>
<td>California Department of Water Resources</td>
</tr>
<tr>
<td>CG</td>
<td>Customer Generator/tion</td>
</tr>
<tr>
<td>CLECA</td>
<td>California Large Energy Consumers Association</td>
</tr>
<tr>
<td>CPM</td>
<td>Capacity Procurement Mechanism</td>
</tr>
<tr>
<td>CPUC</td>
<td>California Public Utilities Commission</td>
</tr>
<tr>
<td>CRS</td>
<td>Cost Responsibility Surcharge</td>
</tr>
<tr>
<td>CT</td>
<td>Combustion Turbine</td>
</tr>
<tr>
<td>CTC</td>
<td>Competition Transition Charge</td>
</tr>
<tr>
<td>D.</td>
<td>Decision</td>
</tr>
<tr>
<td>DA</td>
<td>Direct Access</td>
</tr>
<tr>
<td>DG</td>
<td>Distributed Generation</td>
</tr>
<tr>
<td>DER</td>
<td>Distributed Energy Resources</td>
</tr>
<tr>
<td>DOE</td>
<td>US Department of Energy</td>
</tr>
<tr>
<td>DR</td>
<td>Demand Response</td>
</tr>
<tr>
<td>EE</td>
<td>Energy Efficiency</td>
</tr>
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<td>EECC</td>
<td>Equitable Energy Choice for Californians</td>
</tr>
<tr>
<td>ERRA</td>
<td>Energy Resource Recovery Account</td>
</tr>
<tr>
<td>ESP</td>
<td>Electric Service Provider</td>
</tr>
<tr>
<td>GAM</td>
<td>Green Allocation Mechanism</td>
</tr>
<tr>
<td>GHG</td>
<td>Greenhouse Gas</td>
</tr>
<tr>
<td>GRC</td>
<td>General Rate Case</td>
</tr>
<tr>
<td>IOU</td>
<td>Investor Owned Utility</td>
</tr>
<tr>
<td>IRP</td>
<td>Integrated Resource Plan</td>
</tr>
<tr>
<td>LSE</td>
<td>Load Serving Entity</td>
</tr>
<tr>
<td>MEA</td>
<td>Marin Energy Authority (fka MCE – Marin Clean Energy)</td>
</tr>
<tr>
<td>MEC</td>
<td>Marginal Energy Cost</td>
</tr>
<tr>
<td>MGCC</td>
<td>Marginal Generation Capacity Cost</td>
</tr>
</tbody>
</table>
MNDA  Modified Non-disclosure Agreement
MPB  Market Price Benchmark
MPR  Market Price Referent
NBC  Non Bypassable Charge
NPC  Nevada Power Company
NPV  Net Present Value
NQC  Net Qualifying Capacity
NREL  National Renewable Energy Laboratory
O&M  Operations and Maintenance
PCC  Product Content Category
PCIA  Power Charge Indifference Adjustment
PCL  Product Content Label
PG&E  Pacific Gas and Electric Company
PMM  Portfolio Monetization Mechanism
POU  Publicly Owned Utility
PPA  Power Purchase Agreement
PUCN  Public Utility Commission of Nevada
PWRPA  Power and Water Resource Pooling Authority
R.  Rulemaking
RA  Resource Adequacy
REC  Renewable Energy Credit
RFO  Request for Offer
ROC  Ratepayer Obligation Charge
RPS  Renewables Portfolio Standard
RRB  Rate Reduction Bonds
TURN  The Utility Reform Network
SB  Senate Bill
SEC  US Securities and Exchange Commission
SCE  Southern California Edison Company
SDG&E  San Diego Gas & Electric Company
SONGS  San Onofre Nuclear Generating Station
SPA  Staggered Portfolio Auction
SPE  Special Purpose Legal Entity
TAC  Transmission Access Charge
UCAN  Utility Consumers' Action Network
UOG  Utility Owned Generation
URG  Utility Retained Generation
VAAC  Voluntary Allocation & Auction Clearinghouse
VEPP  Vermont Electric Power Producers
WACC  Weighted Average Cost of Capital
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OPENING BRIEF OF THE
CALIFORNIA COMMUNITY CHOICE ASSOCIATION

Pursuant to Rule 13.11 of the California Public Utilities Commission’s Rules of Practice
and Procedure and the Amended Scoping Memo and Ruling of Assigned Commissioner issued
March 2, 2018, in Rulemaking 17-06-026, the California Community Choice Association
(CalCCA) submits this concurrent opening brief. Each section identifies the corresponding
section of the common briefing outline generally agreed to by the parties.

I. INTRODUCTION AND EXECUTIVE SUMMARY (Common Outline §§I & II)

The Joint Utilities estimate that from 2018 through 2041, uneconomic portfolio costs will
total an estimated $49.68 billion, with more than half of that amount forecast for Pacific Gas and
Electric Company’s (PG&E’s) service territory. ¹ This staggering estimate requires the
Commission to entertain two opposing views: “either the investor-owned utility resource
portfolios are wildly ‘out of the money’ or the benchmark used to evaluate market value requires
reform.”² While the Joint Utilities’ portfolios present real and significant problems, the
magnitude of these problems is considerably exaggerated by the use of a “market price”
benchmark that undervalues those portfolios under the current Power Charge Indifference

¹ See IOU Projections of Above-Market Costs, Workpapers to Appendix D of Exhibit IOU-5.
² Exh. CalCCA-1, Prepared Direct Testimony of the California Community Choice Association, at
1-1:4-7.
Adjustment (PCIA) methodology (Current Methodology). Moreover, while the Joint Utilities contend that the Current Methodology shifts responsibility for uneconomic costs from departing load customers to bundled customers, CalCCA reaches the opposite conclusion: the Current Methodology, by undervaluing portfolio resources, shifts costs from bundled customers to departing load customers. While there is no certain way to determine the extent of the cost shift, CalCCA estimates that the Current Methodology results in a cost shift from bundled to departing load customers for 2018 of up to $492 million annually by PG&E and up to $25 million annually by SCE, increasing as departing load increases over time. The Current Methodology thus requires correction.

While the allocation of uneconomic costs is the Commission’s central mission in this rulemaking, the issue cannot be viewed in isolation, despite the Joint Utilities’ contentions to the contrary. The impact on customers of changes in the cost allocation will depend partly on the magnitude of the costs being allocated. To mitigate customer impacts requires consideration of measures to reduce total portfolio costs; securitization of utility owned generation (UOG) assets, buydown and securitization of existing long-term power purchase agreements (PPAs) and changes in portfolio management practices can reduce existing uneconomic costs and prevent their further accumulation. In addition, the manner in which existing portfolio resources are owned and controlled will not only affect total portfolio costs, but will influence the extent of “double procurement” by other LSEs. Critically, all of these issues – the magnitude of costs, the

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3 The cost shift estimates are based on projected 2018 departing load of 40.9% for PG&E and 3.9% for SCE. If SCE’s CCA departing load were assumed to rise to 40.9% as it is in PG&E’s territory, then the indicative 2018 cost shift for SCE would increase from $25 million to $264 million. Exh. CalCCA-1 at 2A-14: Footnotes 14 and 15.

4 The Joint Utilities have made clear from the outset that their “interest in this proceeding is limited solely to ensuring appropriate cost allocation between groups of customers.” Exh. IOU-1, Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, Power Charge Indifference Adjustment, Prepared Testimony (Public Version), at 1-3:20-22.
allocation of costs and the allocation of resources – carry the potential to interfere with
continuing CCA formation and operation.

It would be tempting for the Commission, given its traditional regulatory orientation, to
focus the design of any solution on protecting bundled customers. Given the potential impacts
on CCAs, the strength of Legislative directives supporting their formation, and SB 350’s clear
mandate to prevent cost shifts in any direction, the Commission must also view the problems and
solutions in this rulemaking through the lens of Community Choice Aggregation. The
Legislature enacted this program to permit customers to “aggregate their electrical loads as
members of their local community with community choice aggregators.”5 The program has been
a fixture of the California electricity market since 1996, when it was originally enacted in
Assembly Bill (AB) 1890.6 While the program was suspended by AB 1X7 in 2001 in the wake
of the energy crisis, the Legislature was quickly reauthorized and modified the program through
AB 117 in 2002,8 demonstrating the state’s commitment to the idea of local governments serving
their own communities.

The Legislature envisioned CCAs as partners with the utilities and state agencies in
driving energy efficiency and conservation,9 increasing reliance on renewable resources10 and
ensuring grid reliability.11 This well-conceived partnership carries the potential to accelerate and
enhance achievement of important state goals – including climate change and social justice – and
to facilitate the design of products and services that best meet consumers’ needs. CCAs play a

6  Assembly Bill 1890 (Stats. 1996, ch. 854) (hereafter, AB 1890).
8  AB 117, supra.
9  Id.
10  Senate Bill 1078 (Stats. 2001, ch. 516) (hereafter, SB 1078).
unique role in this partnership due to their ability to better understand and respond to the needs of the communities they serve, leverage coordination with local governments and, in the longer term, leverage local government financing. CCAs have embarked on this path through the creation of programs aimed to develop small, local renewable resources, encourage energy efficiency, drive transportation electrification, and assist low-income communities. Their efforts are leading the way for other newly launched and future CCAs to follow and enhance this early progress.

The Legislature has tasked the Commission with ensuring the success of its vision. In realizing that vision, the Commission must:

- Enforce cooperation by the utilities “with any community choice aggregators that investigate, pursue, or implement community choice aggregation programs;”
- “Foster fair competition” between CCAs and utilities;
- Certify CCA implementation plans;
- Prevent cost shifts between bundled and departing load customers;
- Ensure that a CCA is “solely responsible” for its own procurement, unless otherwise permitted by statute; and
- Ensure CCA RPS and RA compliance.

More generally, the Commission must “provide Community Choice Aggregators with the opportunity to compete on a fair and equal basis with other load serving entities, and to prevent

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12 See, e.g., https://www.maccleanenergy.org/local-projects/
13 Ex. Cal CCA-3, Exh. 1-B; see also, e.g., https://sonomacleanpower.org/faq/.
14 Id. §366.2(c)(9)-(11)
15 Senate Bill 790 (Stats. 2011, ch. 599, §2(h)) (hereafter, SB 790).
17 Id. §366.2(a)(4); see also id. §366.3.
18 Id. §366.2(g).
19 Id. §399.11.
20 Id. §380.
investor-owned electric utilities from using their position or market power to undermine the
development or operation of aggregators.”21 The Commission also maintains its general
obligation to adopt rates that are just and reasonable.22

Today roughly 40% of PG&E’s and 4% of SCE’s native load is served by Energy Service
Providers (ESPs) or Community Choice Aggregators (CCAs).23 With more CCAs preparing to
launch in 2018, the program has the potential to reach 85% of load in the utilities service
territory by the mid-2020s.24 As this transition continues to unfold, CalCCA’s proposals,
summarized below, allow the Commission to fulfill each of its statutory responsibilities, as well
as the Scoping Memo’s Guiding Principles. These proposals also address the three major areas
of concern: the magnitude of uneconomic costs, the allocation of these costs and the ownership
and control of portfolio resources. CalCCA proposes a measured and phased transition toward a
model that addresses these issues in a durable way, ensuring adequate time for studied
decisionmaking and enabling California to realize its CCA vision.

A. The Commission Plays a Central Statutory Role in Realizing the
   Legislature’s Vision for a Partnership Among the State, Joint Utilities and
   Other LSEs to Implement State Policy Goals.

1. The Commission Must Prevent Cost Shifts Between Bundled and
   Departing Load Customers

This rulemaking was instituted primarily to implement the Commission’s responsibility
to prevent cost shifts between bundled and departing load customers.25 The Scoping Memo
declares preventing cost shifts as the “Overall Goal of this Proceeding.”26 As the Scoping Memo

21 D.12-12-036 at 2; see SB 790 at § 2(h); see also Cal. Pub. Util. Code § 707(a)(4)(A).
23 Exh. IOU-1 at 1-1:18-23.
24 Id.
25 Scoping Memo at 20.
26 Scoping Memo at 13.
observes, however, the Legislative directives to avoid cost shifts do not solely protect bundled customers. The statutory prohibitions of cost shifting require equal treatment, prevent cost shifts from departing load to bundled customers and from bundled to departing load customers. The object of this rulemaking thus is to provide equal treatment for bundled and departing load customers, and it should not be viewed solely as an opportunity to reduce or maintain bundled rates.

With respect to CCA departing load, the Legislature has defined the scope of cost responsibility for “estimated net unavoidable electricity purchase contract costs.” The Legislature further has mandated that the costs:

…shall be reduced by the value of any benefits that remain with bundled service customers, unless the customers of the community choice aggregator are allocated a fair and equitable share of those benefits.

Relying on the scope directed by the Legislature, CalCCA concludes that the Current Methodology does not achieve “indifference” between these customer groups. The Current Methodology results in a cost shift from bundled to departing load customers for 2018 of up to $492 million annually by PG&E and up to $25 million annually by SCE, increasing as departing load increases over time.

“Uneconomic,” “stranded” or “above-market” portfolio costs, in the context of the PCIA calculation for CCA departing load customers, are most easily understood as the difference between portfolio costs and portfolio value. Uneconomic costs have generally been defined as

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29 Id. §366.2(g).
30 The cost shift estimates are based on projected 2018 departing load of 40.9% for PG&E and 3.9% for SCE. If SCE’s CCA departing load were assumed to rise to 40.9% as it is in PG&E’s territory, then the indicative 2018 cost shift for SCE would increase from $25 million to $264 million. Exh. CalCCA-1 at 2A-14: Footnotes 14 and 15.
costs “that may become uneconomic as a result of a competitive generation market, in that these costs may not be recoverable in market prices in a competitive market.”31 The analysis, however, does not stop with an examination of “market” prices, as the Joint Utilities would suggest. The Legislature has made clear that any costs not recoverable in the market “shall be reduced by the value of any benefits that remain with bundled service customers….”32 In other words, uneconomic costs to be allocated through the PCIA are “above-market” costs offset by remaining portfolio value or, as defined by AB 117, the “estimated net unavoidable costs.”33

While costs are relatively straightforward to identify, estimating value is challenging due to California’s regulatory framework, as the Joint Utilities admit.34 Using a reasonable method of estimating value, however, the Current Methodology understates the value of the Joint Utilities’ portfolios. It fails to recognize valuable attributes in the portfolios, including GHG-free resource value, understating the annual 2018 value by as much as $655 million for PG&E and $219 million for SCE.35 It also materially undervalues the Joint Utilities’ portfolios by as much as $475 million for PG&E and $298 million for SCE by relying on short-term RA prices as a proxy for capacity value,36 and by as much as $10 million for each of PG&E and SCE by failing to recognize the value of ancillary services.37 In doing so, the Current Methodology also ignores the value of long-term resources, such as hedge value, optionality value and the value of avoiding RA and RPS compliance penalties. While it understates portfolio value, the Current Methodology overstates the costs of the Joint Utilities’ portfolios that must be shared with CCA

32 Id. §366.2(g).
33 Id. §366.2(f)(2).
34 Ex. IOU-1 at 2-10.
36 Id. at 2B-9:5-7.
37 Id. at 2B-10:1-2.
customers to prevent cost shifts. It includes hundreds of millions of dollars annually of uneconomic costs of Legacy UOG –$545 million for PG&E and $270 million for SCE in 2018 alone – that are not within the statutory scope of cost responsibility for CCAs. 38

Changes to the Current Methodology are required to correct this significant cost shift. CalCCA proposes corrections to the Current Methodology that will result in a more reasonably representative portfolio valuation and align the scope of PCIA-eligible portfolio costs with Legislative directives.

2. The Commission Must Preserve CCAs’ Rights to Be Solely Responsible for Procurement on Behalf of Their Customers.

In addition to preventing cost shifts, the Commission must preserve the rights of CCAs to be “solely responsible” for procurement on behalf of their customers, unless the Legislature has otherwise authorized. 39 The Scoping Memo expressly recognizes these rights, providing that solutions in this proceeding “should allow alternative providers to be responsible for power procurement activities on behalf of their customers, except as expressly required by law.” 40 The Joint Utilities’ Green Allocation Mechanism and Portfolio Monetization Mechanism (GAM/PMM) proposal threatens the Commission’s ability to fulfill this statutory directive. The GAM/PMM would force portfolio attributes into CCA portfolios, regardless of a CCA’s need or procurement strategy, leaving CCAs little or no ability to trade the products in the market without a loss of value. This involuntary product allocation is not authorized by statute and would materially impede a CCA’s statutory right to be “solely responsible” for procurement on behalf of its customers. 41

38 Exh. CalCCA-1 at 2B-21, Table 2B-1, Exh. CalCCA-3 at 7-9: fn. 126.
41 See infra Section III.
CalCCA acknowledges that a solution is required to address the growing mismatch between bundled utility portfolio resources and bundled load, as CCA load grows. CalCCA proposes a Staggered Portfolio Auction, which will allow voluntary, market-based redistribution of portfolio resources by the end of 2021, enabling ESPs, CCAs and the Joint Utilities to create a portfolio that meets the needs of their customers. Adoption of this proposal would allow the Commission to meet its statutory obligations to preserve CCAs’ rights to autonomy in building their portfolios.

3. The Commission Must Prevent the Utilities from Using Their Dominance to Undermine CCA Development or Operation and Ensure Fair Competition between the Joint Utilities and Other LSEs.

To fulfill the Legislature’s vision for CCAs and the Commission’s own commitments to preserve fair competition among LSEs, the Commission must prevent the use of utility dominance to undermine CCA development or operation. The GAM/PMM, however would allow the utilities, in the face of substantial declines in load, to continue to maintain ownership, control and sole access to critical market information for the portfolio resources used to serve their competitors’ customers. It would thus reinforce utility dominance and market power, creating an undue advantage to bundled utility customers over customers of a CCA.

CalCCA’s proposal mitigates the potential for the misuse of the Joint Utilities’ position to the disadvantage of the customers of other LSEs. Rather than permitting the Joint Utilities to continue to retain supply portfolios far in excess of their bundled needs, the Staggered Portfolio Auction allows the realignment of bundled supply and demand. The SPA allocates not only the short-term use of a portfolio resource, as proposed by the Joint Utilities, but long-term control

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42  SB 790 at §2(h).
and potential ownership of the resources.\textsuperscript{43}

4. \textbf{The Commission Must Ensure Just and Reasonable Rates}

Beyond cost allocation and supply distribution, this rulemaking implicates the Commission’s overall responsibility to ensure just and reasonable rates. The Public Utilities Code permits the Commission to allocate to CCA departing load only the “unavoidable” costs of the utility portfolio, excluding costs that are avoidable.\textsuperscript{44} While not similarly articulated in statute for bundled or DA customers, no reasonable rate for any customer should include “avoidable” costs. Consequently, the Commission must ensure that the utilities minimize portfolio costs for all customers and exclude avoidable costs from recovery through the PCIA.

CalCCA alone has provided proposals in this proceeding aimed to reduce costs where avoidable, including securitization of UOG rate base\textsuperscript{45} and buydown and securitization of long-term PPAs.\textsuperscript{46} CalCCA further has proposed measures to prevent the increase of the existing uneconomic cost problem, improving departing load forecasting, modifying procurement practices and more actively managing portfolios.\textsuperscript{47}

B. \textbf{CalCCA Proposes a Phased Transition Plan to Allocate Uneconomic Costs and Accommodate Future CCA Growth Consistent with the Commission’s Statutory Obligations}

The magnitude and complexity of the coming changes in the procurement market require a comprehensive solution consistent with governing statutes. CalCCA proposes a phased solution, correcting the Current Methodology in the near term and transitioning over the next 2-3 years to a more durable framework for the future.

\textsuperscript{43} \textit{See infra} Section VII.B.2.
\textsuperscript{45} \textit{See infra} Section X.
\textsuperscript{46} \textit{Id.}
\textsuperscript{47} \textit{See infra} Section IX.A.
In the near term, the Commission must mitigate the cost shift under the Current Methodology. CalCCA proposes to mitigate the existing cost shift from bundled to departing load customers by correcting the administratively determined benchmark employed by the Current Methodology to better reflect the scope and characteristics of portfolio cost and value (Corrected Methodology). Several changes must be made to correct the value side of the equation:

- Replace the current short-term capacity value with a Commission-adopted long-term resource value;\(^{48}\)
- Add a component to account for the value of GHG-free resources not currently reflected in the benchmark;\(^ {49}\)
- Add a component to account for the value of ancillary services value not currently reflected in the benchmark.\(^ {50}\)

CalCCA also proposes minor modification of the Green Adder to remove the outdated DOE value component.\(^ {51}\) To correct the cost side of the uneconomic cost equation, CalCCA proposes removing Legacy UOG costs from CCA cost responsibility.\(^ {52}\)

The Corrected Methodology should remain in place until the Staggered Portfolio Auction (SPA) can be implemented. The SPA would replace the value measures for GHG-free and RPS resources; the Corrected Methodology would remain in place for fossil resources until they are no longer included in the PCIA-eligible portfolio. The SPA would require the Joint Utilities to offer all RPS-eligible and GHG-free resources into the market on a long-term basis through eight quarterly auctions, beginning on January 1, 2020. The Joint Utilities, CCAs, ESPs and other market participants would voluntarily purchase resources in the auction, choosing the products

\(^{48}\) See infra Section VII.A.1. at 50.
\(^{49}\) See infra Section VII.A.2. at 59.
\(^{50}\) See infra Section VII.A.3. at 60.
\(^{51}\) See infra Section VII.A.4. at 63.
\(^{52}\) See infra Section V.A.4. at 33.
they need to meet their customers’ needs. The SPA thus would ensure voluntary redistribution of utility portfolio resources and generate more reasonably representative market prices to draw boundary between uneconomic and economic portfolio costs.

As the short- and long-term changes are being implemented, the Commission should also direct the utilities to embark on a serious campaign to reduce their overall portfolio costs. First, the utilities should be strongly encouraged to securitize all of their UOG assets, lowering the costs of financing; in the first year, this would reduce portfolio costs by $496 million for PG&E and $131 million for SCE. 53 Over the 20-year term of a securitization bond issuance, the benefits have a net present value of $1.3 billion for PG&E and $589 million for SCE. 54

Changes to portfolio management may also prevent further accumulation of uneconomic portfolio costs. CalCCA recommends modifications to the Joint Utilities’ forecasting practices to better account for departing load. CalCCA also recommends improvements in the Joint Utilities’ portfolio management practices:

- Requiring more active management of the portfolio in response to departing load;
- Prohibiting practices aimed to protect bundled ratepayers at departing load customers’ expense; and
- Requiring optimization of sales from the Joint Utilities’ portfolios to capture the full value of the resources for all customers.

These changes will reduce and more equitably allocate PCIA-eligible costs.

In addition to a transition plan to address utility portfolio costs, allocation and supply redistribution, CalCCA offers several additional proposals:

- Permit prepayment of uneconomic cost responsibility by CCAs and ESPs on behalf of their customers;

53 See infra Section X.C.; Exh. CalCCA-1 at 2A-16, Figure 2A-4 and 2A-17, Figure 2A-5.
54 Exh. CalCCA-1 at 3-7:7-9
 Modify vintaging rules to ensure that departing load customers are not saddled with the costs of contracts that are not reasonably “attributable to” those customers;

Maximize the availability of information to CCAs and ESPs in the ERRA proceedings to facilitate long-term PCIA forecasts.

Require the Joint Utilities to present uneconomic portfolio costs as a separate line item on bundled customer bills to better align customer understanding of the rates they pay.

Adoption of these proposals will enable the Commission to fulfill its statutory role and the Guiding Principles established by the Scoping Memo.

II. BACKGROUND (Common Outline §I)

The PCIA has its roots in the efforts of the Legislature and the Commission to transition the State to a competitive electricity market, which efforts were interrupted by the California energy crisis of 2000-2001. In 1996, the Legislature enacted Assembly Bill 1890, which contemplated the possibility of utility divestiture of generation assets and anticipated a full transition to a competitive market by 2002. AB 1890 created a nonbypassable charge to be paid by all electricity customers, regardless of supplier, that was designed to allow the utility to recover the above-market sunk costs of resources that would become uneconomic in the transition to competition. The charge was implemented by the Commission as the “Competition Transition Charge.” The Commission intended to transition to full competition “as

56 AB 1890, supra, § 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….”).
quickly as possible so that full competition can begin with minimal market distortions.”

In fact, the Commission intended that the collection of the CTC would be completed by 2005.

The PCIA that is in place today is based on a concept established during the energy crisis. At that time, due to a rapid and unforeseen shortage of available electric power, the Legislature authorized the California Department of Water Resources (CDWR) to enter into contracts for the purchase of electric power for delivery to retail customers of PG&E, SCE and SDG&E. CDWR did so, purchasing energy on behalf of all customers, bundled service and DA customers alike. The Legislature also directed the Commission to suspend the right of customers to enter into direct access arrangements with non-IOU providers of electricity.

The Commission determined that in order to avoid a cost-shifting effect, DA customers should be required to pay a portion of costs that were incurred by the State during the crisis on behalf of all retail end use customers in the service territories of the three utilities. The Commission adopted a “cost responsibility surcharge” methodology, which incorporated a “DWR Power Charge” aimed to determine the uneconomic cost of the CDWR long-term contracts on an annual basis. Relying in part on the Commission’s general ratemaking authority under Sections 701, 451, and 453, the Commission also adopted a “separate charge to cover the ongoing above-market portion of utility-related generation costs,” allowing for the

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58 D.95-12-063, 64 CPUC 2d 1 at 60.
59 Id. at 58.
60 AB 1X, supra
61 Id.
62 D.02-03-055, Finding of Fact 3.
63 D. 02-03-055, Ordering Paragraph 3, as modified by D.02-04-067.
64 D.02-11-022 at 3-4.
netting of above-market CDWR and then-below-market Legacy UOG costs in the utility portfolio.\(^{65}\)

To calculate these components, the Commission adopted a “DA In – DA Out” methodology to determine the increase in the average generation cost to the bundled service customers as the result of the departure of some customers to DA service. The CRS could then be calculated as a charge to DA customers required to maintain a steady average rate for generation for bundled customers. This model was later amended by replacing the market prices used in the calculation with an administratively determined “marked price benchmark” (MPB).\(^{66}\)

Also in 2002, the Legislature authorized Community Choice Aggregation through the enactment of Assembly Bill 117. Once again the Legislature sought to prevent cost shifts between bundled and departing customers.\(^{67}\) AB 117 expressly required CCA customers to bear cost responsibility for CDWR historical purchases and the long-term contracts negotiated by CDWR during the energy crisis, via the “DWR Bond Charge”\(^{68}\) and a “DWR Power Charge,”\(^{69}\) respectively. In addition, the Legislature required CCA customers to reimburse the utility for certain balancing accounts\(^{70}\) and “[a]ny 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.”\(^{71}\)

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\(^{65}\) Id. at 4.

\(^{66}\) D.06-07-030. Although the methods for calculating the CRS were determined and adopted by the Commission for DA and CG departing load in R.02-11-011, they were also adopted for calculation of CCAs’ CRS in R.03-10-003 (see D.04-12-046 and D.07-01-025).


\(^{68}\) Id. §366.2(e)(1). The long-term contracts have since terminated.

\(^{69}\) Id. §366.2(e)(2).

\(^{70}\) Id. §366.2(f)(1) (“the electrical corporation’s unrecovered past undercollections for electricity purchases, including any financing costs, attributable to that customer, that the commission lawfully determines may be recovered in rates.”).

\(^{71}\) Id. §366.2(f)(2).
Drawing from prior nonbypassable charge decisions and models developed for DA CRS, the Commission implemented AB 117 through Decision 04-12-046, and adopted a Cost Responsibility Surcharge model for CCA customers. (Although the Commission adopted the previously established methodology developed within the DA context, it is not apparent that efforts were made to ensure the methodology aligned with the specific language of AB 117, which envisioned an entirely distinct form of departing load.) Later on the Commission expanded the CRS in D.04-12-048, including provisions for new or long-term resources used by the utilities to ensure reliability or RPS compliance. The Commission concluded that “the utilities should be allowed to recover the net costs of these commitments from all customers, including departing customers.”

In 2006, the Commission folded the indifference calculations for the DWR Power Charge and Legacy UOG together into the “Power Charge Indifference Adjustment,” which was originally designed for DA. The methodology employed to calculate the charge is very similar to what we have today. The PCIA was intended to recover, on an annual basis, the difference between a revised benchmark power cost and “the average cost of the utilities’ total portfolio, including both utility retained generation power and allocated DWR power costs, to determine the level of the indifference charge for each year.” The 2006 decision also added a capacity value in the indifference calculation, which had until then been based solely on energy costs.

Nearly four years after full Commission implementation of CCA, in 2010 Marin Clean Energy became the first CCA to begin service. The Commission and Legislature attributed the
slow launch of CCAs, in part, to activities by the investor owned utilities. PG&E’s highly disruptive behavior, in particular, led to legislative and Commission action to prevent IOUs from engaging in costly and often misleading campaigns against CCAs at the expense of their own bundled customers.\textsuperscript{76} A code of conduct for utility interactions with CCAs was established in 2012, via D.12-12-036. As of today, 20 CCAs are operational or near-operational.\textsuperscript{77}

The MPB and the Current Methodology were last significantly modified in D.11-12-018, prior to the establishment of all but one of the current CCAs. At that time, the Commission determined to increase the MPB by an “RPS adder” to recognize the establishment of renewable procurement standard requirements, and the fact that contracts executed to satisfy the RPS requirements would be relatively more expensive than other conventional generation.\textsuperscript{78} The Commission also adopted a “capacity adder” which was set as the going-forward costs of a simple cycle combustion turbine, to be updated biannually.\textsuperscript{79} The scope of CCA and DA cost responsibility increased in 2014, when the Commission authorized the recovery of the utilities’ energy storage procurement costs through the PCIA.\textsuperscript{80}

Although the parties to this proceeding may not necessarily agree on the specific causes for the current situation, and although they disagree on the means of resolving the issues raised here, they all agree that the current PCIA and its methodology do not achieve the compliance with statutory scheme authorizing CCA formation.

\textsuperscript{77} A table showing existing CCAs and their original launch dates is provided as Exhibit 1-A.
\textsuperscript{78} Specifically, as described in D.11-12-018, the RPS adder is to be calculated as the weighted average of DOE data for premiums paid by customers under voluntary green pricing programs (32%) and the premium paid by the Joint Utilities for renewable resources delivered in the year when the CRS is calculated and the prior year (68%).
\textsuperscript{79} D.11-12-018 at 30.
\textsuperscript{80} Id. at 22.
III. THE LEGISLATURE HAS CREATED A ROADMAP FOR ASSESSING AND REFINING THE CURRENT METHODOLOGY (Common Outline §I)

The Public Utilities Code provides a clear roadmap for resolving the issues raised in this proceeding. First, the law requires the Commission to avoid “cost shifts” among customer classes. AB 117 provided explicit guidance on the categories of costs that must be recovered from CCA departing load customers to prevent cost shifts to bundled customers. SB 350 also required the Commission to prevent the costs of procurement under the Integrated Resource Plan program from being shifted between bundled and departing load customers. Second, while the law permits the allocation of specific costs to CCA departing customers, it narrowly limits the ability of a utility to go beyond that scope and interfere with a CCA’s procurement strategy. SB 790 granted CCAs full procurement autonomy in serving their customers, except where specifically authorized by statute. The Commission must keep these statutory guidance firmly in mind when addressing the many complex issues raised in this rulemaking.

A. The Legislature Has Specifically Identified the Procurement Costs that Must Be Allocated to Prevent Cost Shifts

In authorizing the formation of CCAs in 2002, the Commission mandated 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…”81 Those specified subdivisions required CCA departing load customers to bear responsibility for several specific categories of costs:

- Department of Water Resources bond charges82
- “Department of Water Resources' estimated net unavoidable electricity purchase contract costs”83

82 Id. §366.2(e)(1).
“[U]nrecovered past undercollections for electricity purchases, including any financing costs.” 84

A CCA customer’s “share of the electrical corporation’s estimated net unavoidable electricity purchase contract costs attributable to the customer” 85

The Legislature further provided that the customer’s cost share “shall be reduced by the value of any benefits that remain with bundled service customers, unless the customers of the community choice aggregator are allocated a fair and equitable share of those benefits.” 86

The Legislature next spoke on the issue of CCA cost shifts in 2005, enacting a resource adequacy mandate to be applied to all LSEs, including CCAs. Section 380(b)(2) requires the Commission to “[e]quitably allocate the cost of generating capacity and prevent shifting of costs between customer classes.” 87 The Legislature provided the Commission flexibility in achieving this goal to “consider a centralized resource adequacy mechanism among other options,” 88 which was the root of the Cost Allocation Mechanism adopted in D.06-07-029. At the same time, the Legislature made clear that CCAs “shall be subject to the same requirements for resource adequacy” as other LSEs and reiterated their obligations under the Renewables Portfolio Standard program. 89 It addressed RA again in 2009, making clear the responsibility of CCAs and other LSEs to bear responsibility for resources contracted by the utility for reliability purposes. 90

83  Id. §366.2(e)(2).
84  Id. §366.2(f)(1).
85  Id. §366.2(f)(2).
86  Id. §366.2(g).
87  Id. §380(b)(2).
88  Id. §380(h).
89  Id. §380(e). CCAs have carried the same RPS compliance obligations as other LSEs since the program was first enacted in 2002. See SB 1078; §399.12(b)(2).
90  Id. §365.1.
Cost shifting was also addressed in 2011 in the enactment of SB 790. While leaving the categories of cost responsibility for CCA departing load customers unchanged, the Legislature directed that “[t]he implementation of a community choice aggregation program shall not result in a shifting of costs between the customers of the community choice aggregator and the bundled service customers of an electrical corporation.” The Legislature thus clarified that the prohibition on cost shifting goes both directions.

Most recently, in 2015, the Legislature again addressed cost shifting in adopting the requirement for LSEs to submit IRPs. The statute requires:

To the extent that additional procurement is authorized for the electrical corporation in the integrated resource plan or the procurement process authorized pursuant to Section 454.5, the commission shall ensure that the costs are allocated in a fair and equitable manner to all customers consistent with 454.51, that there is no cost-shifting among customers of load-serving entities, and that community choice aggregators may self-provide renewable integration resources consistent with Section 454.51.

It further clarifies that the prohibition on cost shifting goes both ways:

Bundled retail customers of an electrical corporation shall not experience any cost increase as a result of the implementation of a community choice aggregator program. The commission shall also ensure that departing load does not experience any cost increases as a result of an allocation of costs that were not incurred on behalf of the departing load.

The statute also provides that “the net costs of any incremental renewable energy integration resources procured by an electrical corporation to satisfy the need identified in subdivision (a)

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91 Id. §366.2(a)(4).
92 Assembly Bill 57 (Stats. 2002, ch. 835). AB 57, which enacted the procurement planning process in §454.5, contained no provisions on cost shifting or cost allocation to customers of other LSEs.
93 Id. §454.52(c) (emphasis supplied).
94 “Cost increase,” set in the context of 20 years of cost shift statutes and Commission decisions, can only be understood to mean and increase in cost, net of benefits.
95 Id. §366.3.
are allocated on a fully nonbypassable basis consistent with the treatment of costs identified in paragraph (2) of subdivision (c) of Section 365.1."\textsuperscript{96}

Through this roadmap, the Legislature has carefully framed and limited the scope of responsibility that must be borne by CCA departing load customers to prevent cost shifts.

- Commencing in 2002 with AB 117, a CCA customer departing utility service bears responsibility for “unrecovered past undercollections for electricity purchases” and the “estimated net unavoidable electricity purchase contract costs attributable to the customer.”

- The Legislature added certain resource adequacy generation costs in 2005.

- Finally, commencing in 2015, the Legislature placed on these customers the costs of \textit{incremental} renewable integration resources procured by the utility through a centralized process, subject to the CCA’s right to self-provide, and the costs of \textit{additional} procurement under the utilities’ bundled procurement plans or IRPs.

The Legislature has not authorized the inclusion of other types of procurement costs – notably Legacy UOG costs – nor has it authorized the allocation of products or benefits from the portfolio, other than certain RA resources, to CCAs.

**B. The Legislature Granted CCAs the Sole Right to Procure Resources on Behalf of Their Customers, Subject Only to Exceptions Specified by Statute**

The Legislature granted CCAs the sole right to procure resources on behalf of their customers. Following the battle for CCA implementation by the Marin Energy Authority (now Marin Clean Energy), the Legislature saw the need for CCA protections to prevent the utilities from impairing CCA formation. Bill analysis observed that a “genesis of this bill has been PG&E’s atrocious behavior surrounding the establishment of the Marin Energy Authority and its

\textsuperscript{96} \textit{Id.} §454.51(c) (emphasis supplied).
CCA program Marin Clean Energy.” In enacting the Charles McGlashan Community Choice Aggregation Act (SB 790), the Legislature made several very important findings:

(a) It is the policy of the State to provide for the consideration, formation, and implementation of community choice aggregation programs authorized in Section 366.2 of the Public Utilities Code.

*   *   *   *   *

(c) Electrical corporations have inherent market power derived from, among other things, name recognition among customers, longstanding relationships with customers, joint control over regulated operations and competitive generation services, access to competitive customer information, and the potential to cross-subsidize competitive generation services.

(d) The Public Utilities Commission has found that conduct by electrical corporations to oppose community choice aggregation programs has had the effect of causing community choice aggregation programs to be abandoned.

*   *   *   *   *

(f) The exercise of market power by electrical corporations is a deterrent to the consideration, development, and implementation of community choice aggregation programs.

(g) California has a substantial governmental interest in ensuring that conduct by electrical corporations does not threaten the consideration, development, and implementation of community choice aggregation programs.

(h) It is therefore necessary to establish a code of conduct, associated rules, and enforcement procedures, applicable to electrical corporations in order to facilitate the consideration, development, and implementation of community choice aggregation programs, to foster fair competition, and to protect against cross-subsidization by ratepayers.

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97 Senate Floor Analysis, September 9, 2011 at 5
In response, the Legislature directed the Commission to develop a code of conduct “to govern the conduct of the electrical corporations relative to the consideration, formation, and implementation of community choice aggregation programs….”98 Importantly, it also provided that “[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.”99

Consequently, while the Legislature has clearly authorized CCA departing load customers’ responsibility for their share of certain costs, it has not granted the utility carte blanche to allocate products or attributes to the CCAs. While Section 366.2(g) contemplates a how to address cost responsibility if customers receive benefits from the portfolio, it does not authorize an allocation of attributes or products. In only one instance – resource adequacy100 – does a statute contemplate the potential allocation of products or attributes to a CCA. Thus, CalCCA’s proposed solution in this proceeding is confined, as required by law, to cost allocation. The allocation of products or attributes, as proposed by the Joint Utilities, does not comport with this requirement.

IV. THE CURRENT METHODOLOGY SHIFTS COSTS FROM BUNDLED CUSTOMERS TO DEPARTING LOAD CUSTOMERS (Common Outline §III)

The first two issues in the Scoping Memo focus on whether the Current Methodology results in a cost shift between bundled and departing load customers.101 CalCCA provided direct testimony regarding these issues, acknowledging that a cost shift assessment is highly sensitive to assumptions and that clear, accurate market value measures are not readily available for all

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99 Id. §366.2(a)(5).
100 Id. §380(h).
101 Scoping Memo at 20.
portfolio products. CalCCA nonetheless concludes, given the substantial differences produced by other Commission-approved value measures, that the Current Methodology’s portfolio value measures are too low. The result is an annual PCIA that is too high and shifts costs from bundled to departing load customers.102

CalCCA observes two primary problems with the Current Methodology’s portfolio value measures as expressed in the benchmark. First, the Current Methodology does not recognize and value all products and attributes in the utilities’ portfolios. Most notably, it does not distinguish between different types of resource adequacy products,103 it does not reflect a value for GHG-free energy104 and it does not reflect a value for ancillary services.105 Moreover, the Current Methodology undervalues portfolio capacity by using a short-term proxy value derived solely from power plant operational costs for System RA only.106 CalCCA also observes that values for these products are not easily divined, which CalCCA illustrates by identifying the range of different economic values the Commission uses for capacity, ancillary services, avoided GHG and avoided RPS costs, as shown in Table 2A-3.107

102 Exh. CalCCA-1 at 2A-12-17.
104 Id. at 2B-10-11.
105 Id. at 2B-9-10.
106 Id. at 2B-7-9.
107 Id. at 2A-11.
Simply substituting two of the value measures in the Current Methodology for 2017 – capacity and the Green Adder – with the comparable value measures from the Commission’s Avoided Cost Calculator, suggests that $173 million annually is being shifted from PG&E’s bundled to departing load customers. This conclusion flips on its head PG&E’s conclusions supporting its Equitable Energy Choice for Californians claims that $178 million was shifted from departing load customers to bundled customers during the same period. The differences are illustrated in Figure 2A-1:

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109 See Exh. CalCCA-100, Equitable Energy Choice for Californians, Fact Sheet (concluding that “some customers who now receive power through an alternative energy provider may on average only pay roughly 65% of the cost of clean energy that was purchased on their behalf.”). PG&E was involved in the formation of EECC and had a role in estimating the cost shift described on the fact sheet. 1 Tr. 69:10 – 70:8.
Taking this analysis one step further, adjusting the Current Methodology to reflect all of CalCCA’s proposed refinements to value measures, produces an even greater cost shift from bundled to departing load customers. Assuming that departing load constitutes 40.9% of PG&E’s service territory load and making a simplifying assumption that cost allocation to various customers is proportional to load share, CalCCA estimates that departing load customers in 2018 will pay PCIA costs that are roughly $492 million (54%) greater than the costs that are reasonably attributable to them. Assuming that departing load constitutes 3.9% of SCE’s service territory load, CalCCA estimates that departing load customers in 2018 will pay PCIA costs that are roughly $25 million (53%) greater than the costs that are reasonably attributable to them.

The calculations compare the 2018 ERRA results for each utility with a scenario that adjusts the value measure for capacity, removes the DOE element of the RPS value measure, adds a GHG-free value and adds an ancillary service value; the scenario also excludes PG&E’s Humboldt costs and SCE’s Pebble Beach costs as inappropriately included in the scope of PCIA-eligible costs. The scenario does not net the benefits of securitization, which would accrue to all bundled and departing load customers. See Exh. CalCCA-1, Figure 2A-4 at 2A-16 and Figure 2A-5 at 2A-17.

See Exh. CalCCA-1, Figure 2A-4 at 2A-16, $492,155/($1,204,596 *.409).

See Exh. CalCCA-1, Figure 2A-5 at 2A-17, $25,411/($646,677 *.039).
Beyond the changes in portfolio value measures, the scope of costs attributed to CCA customers in the PCIA calculation is materially broader than contemplated by statute. As discussed in Section III above, the Legislature has defined the scope of costs that may be recovered from CCA departing load customers to prevent cost shifts to bundled customers.\textsuperscript{113} Most notably, as discussed in Section V below, the Legislature did not contemplate recovery from these customers of the utilities’ Legacy UOG costs.\textsuperscript{114} CalCCA estimates that for 2018, PG&E’s PCIA included $545 million in uneconomic Legacy UOG costs.\textsuperscript{115} Based on the same simplified assumption that cost allocation is proportional to load share, CCA departing load’s share of those costs – 40.9% – represents a $222 million overpayment to bundled customers.\textsuperscript{116}

The Joint Utilities provided no direct testimony addressing cost shifts under the Current Methodology, despite PG&E’s role in presenting cost shift estimates publicly through the Equitable Energy Choice for Californians website and public campaigns.\textsuperscript{117} Only in rebuttal was any attempt made to quantify a cost shift under the Current Methodology, and only PG&E performed this calculation.\textsuperscript{118} While also acknowledging the difficulty in identifying value

\textsuperscript{113} See supra at 16.
\textsuperscript{114} See infra at 28.
\textsuperscript{115} Exh. CalCCA-1 at 2B-21, Table 2B-1.
\textsuperscript{116} Note that the $222 million cost shift from Legacy UOG is not additive to the $492 million cost shift from refined valuation benchmarks since the two calculations overlap in terms of the resources being valued and the benchmarks being used to value them. However, this comparison does illustrate that roughly 45% of CalCCA’s asserted cost shift ($222 million / $492 million = 45%) is validated simply by recognizing that recovery of Legacy UOG costs is unauthorized and inappropriate.
\textsuperscript{117} See Exh. CalCCA-100, Equitable Energy Choice for Californians, Fact Sheet (concluding that “some customers who now receive power through an alternative energy provider may on average only pay roughly 65% of the cost of clean energy that was purchased on their behalf.”). PG&E was involved in the formation of EECC and had a role in estimating the cost shift described on the fact sheet. 1 Tr. 69:10 – 70:8.
\textsuperscript{118} Exh. IOU-3 at 2-35:16-30.
measures for all products and attributes – particularly capacity value – PG&E concludes that a cost shift is occurring in the opposite direction, from departing load to bundled customers. In other words, the portfolio value measures are, in PG&E’s view, too high and the PCIA is too low.

PG&E estimates that in 2018, a cost shift between $190 million and $259 million is occurring from departing load to bundled customers. The estimates rely on two downward changes to value measures under the Current Methodology. Even the low end of PG&E’s cost-shift estimate lacks credibility.

PG&E replaces the short-run reliability adder value for 2018 ($58.27/kW-year) with the 2016 RA Report NP-26 Average Value for short-term sales of excess capacity. As explained in Section VII.A.1, this value is unreliable because it not only excludes any long-term capacity value, but because it relies data representing only 20% of the RA capacity in the market. In essence, PG&E is simply using the wrong product as a proxy. PG&E’s use of this adder also ignores the Joint Utilities testimony that there is no available market price that measures the full value of capacity.

PG&E replaces the Green Adder with an alternative value, using the “Mid-point of positive values from Figure 2-2 of the Joint Utilities Prepared Testimony.” Again, this measure is wholly unreliable. First, the Joint Utilities acknowledge that the chart in Figure 2-2 is

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119 Exh. IOU-1 at 5-9:21-23 (“Thus, a market does not exist that would provide additional revenues to compensate for the full capacity value of post-2002 UOG resources.”).
121 Id. (referring to Exh. CalCCA-109, Table 7, NP-26 Average Price ($kW/month)).
122 See infra at 50-51.
123 Exh. IOU-1 at 5-9:21-23 (“Thus, a market does not exist that would provide additional revenues to compensate for the full capacity value of post-2002 UOG resources.”).
“not intended to be exhaustive.” Second, there is no way to know whether this chart fairly represents the broader range of transactions in the market, particularly because the table, on its face, does not include any transactions in which one of the Joint Utilities is a counterparty. Third, all of the transactions shown in the table indicate that they are transactions for solar resources, with the exception of one wind project. Finally, even a one-year REC product, represented by the 2018 PCC 1 REC index published by Platt’s, is $16/MWh – materially more than the $11.50/MWh the Joint Utilities derive from Figure 2-2. And, as CalCCA noted in its rebuttal testimony, the Platt’s REC index does not reflect long-term value.

CalCCA acknowledges that there is no certain, precise way to measure the extent of any cost shift occurring under the Current Methodology. Directionally, however, the evidence demonstrates that it is far more likely that a cost shift is occurring from bundled to departing load customers than, as the utilities suggest, the other way around.

V. THE SCOPE OF COSTS THAT MAY BE ALLOCATED THROUGH THE PCIA IS LIMITED BY STATUTE AND PRIOR COMMISSION DECISIONS (Common Outline §IV)

A. Legacy Utility Owned Generation Costs Do Not Fall Within the Scope of Costs That Can Be Allocated to CCA Departing Load Customers

Substantial uneconomic costs of Legacy UOG – utility-owned generation installed before 2002 – are currently recovered from CCA departing load customers through the PCIA. CalCCA estimates that (1) PG&E’s 2018 uneconomic Legacy UOG costs will total approximately $545 million and (2) $270 million in such costs for SCE. The Joint Utilities

125 Exh. IOU-3 at 2-11, n. 23.
126 Exh. AD-1 at 17.
127 Exh. CalCCA-3 at 2B-10:15-17.
128 Exh. IOU-1 at 4-54, n. 81.
129 Exh. CalCCA-3 at 7-9, n. 126.
propose to continue PCIA recovery of these costs from CCA customers but, at the same time, exempt pre-2009 DA customers from paying these costs.

The Joint Utilities proposal is unreasonable and unlawful. Legacy UOG costs, by statute, were intended to have been fully recovered by 2005. Moreover, while CCA customers maintain a legal responsibility for remaining CTC, the Legislature did not impose other Legacy UOG costs on CCA departing load customers. In fact, non-CTC Legacy UOG costs crept into the PCIA in 2002 only to accommodate DA customers, as suggested by D.02-02-011.

Continuing to impose uneconomic Legacy costs on CCAs, while exempting pre-2009 DA customers, is contrary to statutory direction concerning what costs are recoverable from CCAs. The Joint Utilities’ proposal also discriminates against CCA and more recently departed DA customers.

1. **State Law Does Not Require CCA Departing Load Customers to Pay for Legacy UOG Costs**

Legacy UOG costs were originally intended to have been fully recovered by 2005 in the transition to retail competition. Assembly Bill 1890, enacted in 1996, contemplated the possibility of utility divestiture of generation assets and anticipated a full transition to a competitive market by 2002. 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

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130 Id.
132 D.95-12-063, 64 CPUC 2d 1 at 58.
133 See supra at 17.
134 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.
135 AB 1890, §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….”)
nonbypassable charge to be paid by all electricity customers, regardless of supplier.\textsuperscript{136} 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{137} It concluded: “With the exception of CTC arising from existing contracts, \textit{no further accumulation of CTC will be allowed after 2003 and collection will be completed by 2005.}”\textsuperscript{138} The utilities were given clear notice that California was transitioning and had a chance at that time to address uneconomic Legacy UOG.\textsuperscript{139}

Nothing in the governing statutory framework has changed to permit recovery of these costs from departing load customers outside of the CTC. Moreover, the Legislature made clear its intent \textit{not} to recover the costs from CCA departing load customers in AB 117. As discussed in Section III.A, the Legislature carefully prescribed the scope of costs that must be recovered from CCA departing load to prevent a cost shift to bundled customers.\textsuperscript{140} Because the statute was enacted in 2002, the Legislature necessarily was aware the utilities were continuing to operate Legacy UOG and understood the cost recovery provisions of AB 1890. The Legislature elected to include in the scope of CCA departing load cost only CDWR bond and power costs

\begin{footnotesize}
\begin{enumerate}
\item D.95-12-063 at 119.
\item 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 See supra at 17.
\end{enumerate}
\end{footnotesize}
and “electricity purchase contract” costs.\textsuperscript{141} No statute passed since that time has imposed the Legacy UOG costs on CCA or any other departing load customer class.

\textit{Expressio unius est exclusio alterius} – “the expression of one thing implies the exclusion of others”\textsuperscript{142} – is a well-settled canon of statutory interpretation in California law, applied by both state and federal courts. In AB 117, the Legislature specified the costs that were to be borne by departing load customers. Under \textit{expressio unius}, that list must necessarily be interpreted to be exclusive unless a contrary legislative intent is expressed in the statute or elsewhere.\textsuperscript{143} Here, as noted above, there is no contrary legislative intent expressed elsewhere that would preclude the application of \textit{expressio unius} in this case. On the contrary, the Legislature has made its position perfectly clear. Legacy UOG costs may not be recovered from CCA departing load.

2. The Inclusion of Legacy UOG Costs in the PCIA Was Unrelated to and Did Not Materially Benefit CCA Departing Load

If the Legislature did not permit continued recovery of non-CTC Legacy UOG costs, how did they find their way into the PCIA? The answer resides in the dynamics surrounding DA that arose from AB 1X. The inclusion of these costs was unrelated to CCA departing load and has provided little benefit to this class of customers over the years.

AB 1X, an urgency statute, enabled the CDWR to begin to procure resources to serve the utilities’ load following the energy crisis. The statute also suspended the rights to enter into DA transactions until the CDWR “no longer suppliers power hereunder.”\textsuperscript{144} In D.01-09-060, the

\textsuperscript{141} Cal. Pub. Util. Code §366.2(e) and (f). The reasons for exclusion may lie in the opposition by bundled ratepayer advocates to allowing lower cost Legacy UOG to offset the DWR Power Charge costs.

\textsuperscript{142} \textit{Dyna-Med, Inc. v. Fair Employment & Housing Com.} (1987) 43 Cal.3d 1379.


\textsuperscript{144} Cal. Water Code §80110.
Commission implemented the AB 1X suspension, effective September 20, 2001.\(^{145}\) The Commission provided notice, however, that it could modify the suspension date to preclude agreements entered into on or after July 1, 2001.\(^{146}\) In D.02-03-055, the Commission elected to retain the suspension date of September 1 on policy grounds, finding:

California is better served by maintaining the September 20, 2001 direct access suspension date and by imposing a direct access surcharge or exit fee, in lieu of an earlier suspension, to recover DWR costs from direct access customers.\(^{147}\)

Later that year, the Commission considered proposals by CLECA and other parties 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.\(^{148}\) 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.\(^{149}\)

The Commission ultimately adopted CLECA’s recommendation in D.02-11-022, imposing the above-market costs of CDWR contracts on DA customers, counterbalanced by including lower cost Legacy UOG and an extension of the implementation date for the AB 1X suspension of DA.

The Commission reexamined the issue of including utility generation in departing load charges in D.08-09-012.\(^{150}\) At the time D.02-11-022 and D.08-09-012 were issued, Legacy UOG were assumed to be “lower cost” than other resources, and therefore would have a mitigating or netting effect on overall departing load charges.\(^{151}\) This fact was acknowledged by PG&E,

\(^{145}\) D.01-09-060 at 2.

\(^{146}\) Id. at 8-9.

\(^{147}\) D.02-03-055, Finding of Fact 6, at 30.

\(^{148}\) D.02-11-022 at 23.

\(^{149}\) Id.

\(^{150}\) See generally D.08-09-012 at 49-52.

\(^{151}\) 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...” 

Page 33 – CalCCA Opening Brief – PUBLIC Version
BN 33100100v2
06/01/2018
which asserted that “departing customers should not receive the benefits of existing generation after they leave bundled service.” Based on the assumption that UOG would lower the overall departing load charge, the Commission adopted a total portfolio approach to the PCIA that not only considered “cost-shifting” from new resources but also allowed UOG resources to be “netted” against this cost-shift.

While DA customers may have benefitted from this netting in the early years, CCAs do not appear to have similarly benefitted. PG&E CCA load departing in 2010 received some benefit, with Legacy UOG costs offsetting other PCIA costs by $429 million. Thereafter, however, Legacy UOG has been consistently uneconomic, contributing $545 in uneconomic costs to PG&E’s 2018 PCIA.

3. Requiring CCA Customers to Continue to Bear Legacy UOG Cost Responsibility While Exempting Pre-2009 DA Customers Would Unlawfully Discriminate Against CCA Customers

AReM/DACC propose to “memorialize” the permanent exemption of Legacy UOG from the PCIA for pre-2009 vintage. Other than present a review of the utilities’ actions in this regard, AReM/DACC have been unable to further explain their rationale underlying the exemption. In light of these facts, it is reasonable to examine in this proceeding whether Legacy UOG costs should be excluded from the PCIA calculation for all departing load customers – not just pre-2009 DA customers.

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152 D.08-09-012 at 49.
153 See D.08-09-012 at 51 (citing in part D.02-11-022 at 25).
154 Exh. CalCCA-3 at 7-13:13-16 and Exhibit 7-A.
155 Exh. AD-1 at 33.
156 Id. at 32; see also 3 Tr. 593:6-594:18 (Fulmer).
ARem/DACC explained that in “in 2016, PG&E ceased collecting a PCIA from pre-2009 vintage DA customers.” An associated issue (retirement of PG&E’s negative indifference balance for pre-2009 customers) was deferred. PG&E’s witness stated that the recovery of Legacy UOG costs ended with the expiration of CDWR contracts, pursuant to D.07-05-055. While it is not entirely clear how the decision was meant to apply, it does provide that “[a]t the expiration of the DWR contract term, the applicability of the indifference requirement would also expire.”

ARem/DACC further observe 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. 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.”

While the record remains unclear, it appears that the rationale for the termination of Legacy UOG cost recovery from pre-2009 DA customers was to maintain symmetry between recovery of CDWR costs and the associated Legacy UOG cost offset. Once CDWR contracts

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157 Id. at 32:5-6.
158 See D.15-12-022 at 23; Ordering Paragraph 5.
159 2 Tr. 385:2-16.
160 D.07-05-055, Finding of Fact 14 at 27.
161 Id. at 32.
162 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).
163 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 filed in I.12-10-013 et al.
expired, there no longer was a need for offset. Whatever the rationale, there is no reason why other DA or CCA customers should remain on the hook for these costs, and the Joint Utilities have not attempted to explain the differences in treatment. The proposed discrimination is unjustified and violates §728, which requires the Commission to reject rates that are “discriminatory” or “preferential.”164

4. The Recovery of Legacy UOG Costs Through the PCIA Should Be Discontinued

It is difficult, if not impossible, to understand why the utilities should be permitted to continue to recover Legacy UOG costs from CCA customers – or any departing load customers – going forward. The utilities should have recovered any uneconomic costs for these resources long ago, as contemplated by AB 1890. Moreover, the Legislature declined, knowing of the existence of these resources and costs, to include these resources in the scope of CCA cost responsibility in AB 117. Finally, the utilities seek to exempt pre-2009 DA customers from these costs, perhaps appropriately, and it would be discriminatory to continue to impose these costs on other departing load customers.

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164 Public Utilities Code Section 728 provides in relevant part “Whenever the commission, after a hearing, finds that the rates or classifications, demanded, observed, charged, or collected by any public utility for or in connection with any service, product, or commodity, or the rules, practices, or contracts affecting such rates or classifications are insufficient, unlawful, unjust, unreasonable, discriminatory, or preferential, the commission shall determine and fix, by order, the just, reasonable, or sufficient rates, classifications, rules, practices, or contracts to be thereafter observed and in force.” In addition, see Pacific Tel. & Tel. Co. v. Public Utilities Com., 62 Cal. 2d 634, 647 (1965) wherein the court stated “the primary purpose of the Public Utilities Act is to insure the public adequate service at reasonable rates without discrimination; and the commission has the power to prevent a utility from passing on to the ratepayers unreasonable costs for material and services by disallowing expenditures that the commission finds unreasonable.”
B. Post-2002 Utility Owned Generation Costs

1. Nothing Has Changed to Warrant Removal of the 10-Year Limitation on Recovery of Post-2002 UOG Costs Through the PCIA

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. The Commission has addressed and retained this limitation in three decisions. While the Commission has left the door ajar for further discussion under specific circumstances, the utilities’ attempts to lift the limitation – 15 years after its first implementation – are unsupported by the record and unjustified.

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

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165 This discussion has been drawn largely from CalCCA-3, Chapter 5, without identification of direct quotations.
166 Exh. IOU-1 at 5-8 to 5-10.
167 D.03-12-059 at 35, Finding of Fact 22.
168 Id. at 32.
169 Id.
the power is not needed…” 170 The Commission’s decision did not authorize SCE to reopen cost allocation of this resource in later years.

The Commission applied this limitation more generally in its 2004 adoption of the utilities’ Long-Term Procurement Plans, extending it prospectively to all “fossil-fueled resources acquired by the utilities either directly or through contract.” 171 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.” 172 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. 173

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. 174

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. 175

170 Id. at 35.
171 D.04-12-048 at 61.
172 Id.
173 Id.
174 Id. at 63.
175 D.08-09-012 at 54-55.
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 recovery period extension is appropriate and necessary for specific non-RPS resources, they can make such requests…”

Despite clear direction from the Commission, very narrowly limiting any extension of the 10-year recovery period for post-2002 UOG costs, the utilities have put forward a vague and unsupported proposal for all such costs to be carried forward. 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.” 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 10-year limit was adopted.” 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

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176 Id. at 55.
177 Exh. IOU-1 at 5-9.
178 Id. at 5-10.
179 D.08-09-012 at 55.
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. Under these circumstances, the Commission’s adoption of the Joint Utilities’ proposal would be unlawful and subject to legal challenge on appeal.

In addition to serious questions of timing and notice, the absence of a capacity market cannot justify the significant modifications the utilities request. There has been 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. As explicitly discussed in D.08-09-012 quoted above, 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. Despite the requirement that the utilities forecast load and adjust their activities to mitigate impacts on bundled customers over time from their UOG, the Joint Utilities have only in the last few years made strides to improve their departing load forecasting.\(^{180}\)

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 is unlawful. The Commission thus has no basis to modify cost recovery for existing post-2002 fossil UOG going forward.

2. **Inclusion of Post-2002 Utility Owned Generation Costs in the CCA PCIA is Limited by Statute**

The Legislature has provided for only limited recovery of post-2002 UOG costs from CCA departing load. AB 117 permitted recovery solely of the costs of “electricity purchase

\(^{180}\) Exh. CalCCA-1 at 3-12.
contracts,” not UOG.\textsuperscript{181} AB 380 expanded the scope to include the costs of certain reliability resources procured through centralized procurement, which occurs through the CAM.\textsuperscript{182} Finally, SB 350 provided for the recovery of certain “incremental” resources required for renewable integration\textsuperscript{183} and prohibited cost shifting in “additional procurement” under the IRP.\textsuperscript{184}

Indeed, there is no legal basis for continuing to include post-2002 UOG costs in the PCIA, particularly for CCA departing load. While the Public Utilities Code gives the Commission broad discretion under §701, that authority does not permit the Commission to move into the scope of CCA customer cost responsibility categories of costs that go beyond those specified in AB 117 without more express statutory authority to do so.

In fact, the Supreme Court of California has already spoken on the issue of the reach of §701. The Commission’s power under that section, according to the Supreme Court “does not authorize disregard by the commission of express legislative directions to it, or restrictions upon its power found in other provisions of the act or elsewhere in general law.”\textsuperscript{185} Thus, the question becomes whether a specific statute conflicts, or may be harmonized, with § 701. In making this determination the Supreme Court has again turned to the maxim \textit{expressio unius est exclusio alterius}.\textsuperscript{186} For example, the Court found that the Legislature’s “express decision” to institute a permissive program cannot reasonably be interpreted to include the authority under § 701 and § 702 to impose a mandatory program.\textsuperscript{187} The same logic applies here. Should the Commission

\begin{footnotesize}
\begin{enumerate}
\item[182] Id. §380(b)(2), (h).
\item[183] Id. §366.3.
\item[184] Id. §454.52(c) (emphasis supplied).
\item[185] Pacific Tel. & Tel. Co. v. Public Util. Com. (1965) 62 Cal.2d 634, 653.
\item[187] Id. at 736.
\end{enumerate}
\end{footnotesize}
extend cost recovery of post-2002 UOG resources beyond the existing 10-year limit, CalCCA reserves the right to contest the legal basis on appeal.

VI. LONG-TERM RESOURCES SHOULD BE VALUED USING LONG-TERM VALUATION MEASURES (Common Outline §V)

Underlying most disputed issues in this proceeding is the question of portfolio valuation. AB 117 defines the scope of CCA stranded cost responsibility as the “estimated net unavoidable costs attributable to” departing load customers, and requires those costs to be “reduced by value of any benefits that remain with bundled service customers….” The Joint Utilities and TURN contend that 100 percent of the long-term resources in the portfolio should be valued using short-term sales prices the utilities “realize” for their limited excess supply. This is akin to saying that a family who purchased a house to obtain the security of a stable, long-term residence places a value on the house equal to the value they can realize for renting out a room in the house on AirBnB. In contrast, CalCCA contends that the Joint Utilities underestimate the value of the bundled portfolio by failing to recognize valuable attributes and ignoring long-term portfolio characteristics and value. To determine the extent of procurement costs to be allocated through the PCIA requires the Commission to make express decisions on the proper method of valuing the Joint Utilities’ portfolios.

A. The Commission Has a Depth of Experience in Portfolio Valuation

The Commission undertakes some sort of valuation in nearly every key proceeding. In ratemaking, it determines the marginal cost of various utility functions, such as generation capacity (MGCC) and energy (MEC). The Commission also values a variety of products

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189 Id. §366.2(g).
190 Exh. SCE-04, phase 2 of 2018 General Rate Case Rate Design Materials at 96.
191 Exh. PCG-E-9, 2017 General Rate Case Phase 11 at 1-2.
and attributes in assessing the value of Energy Efficiency (EE), Demand Response (DR) and Distributed Energy Resources (DER) through the Avoided Cost Calculator (ACC). Using the ACC, the Commission estimates the value of capacity, ancillary services, energy, avoided RPS procurement and avoided GHG.\textsuperscript{192} As discussed further below, the Commission also has experience in long-term valuation in its development and maintenance of the Market Price Referent used in the RPS context.\textsuperscript{193} Likewise, the Commission has calculated avoided capacity and energy costs under the Public Utility Regulatory Policies Act of 1978 for purposes of pricing the sale of power from Qualifying Facilities to the utilities.\textsuperscript{194} Table 2A-3 provides a snapshot of the types of valuation the Commission and the Energy Commission have conducted in the recent past.\textsuperscript{195} In short, the Commission is no stranger to the need to value products and attributes and the techniques to perform the valuation.

The Commission has performed valuation in the context of departing load costs in the past. It valued uneconomic portfolio costs in implementing AB 1890; the costs were measured partly by the proceeds of divested plants and partly using a market price benchmark.\textsuperscript{196} The Commission initially valued the utilities’ portfolios through the “DA In/DA Out” method.\textsuperscript{197} In modifying the PCIA methodology in 2006, the Commission chose to value the portfolio for purposes of determining uneconomic costs using the MPB; it has since modified its valuation methodology, adding the Green Adder in 2011.\textsuperscript{198}

\textsuperscript{193} See infra Section VLC.
\textsuperscript{194} See, e.g., D.10-12-035.
\textsuperscript{195} Exh. CalCCA-1, Table 2A-3.
\textsuperscript{196} AB 1890, supra, at §367.
\textsuperscript{197} See D.06-07-030 at 5.
\textsuperscript{198} D.11-12-018 at 17.
The Commission is asked in this proceeding again to consider methodologies to value the products and attributes in the Joint Utilities’ portfolios. CalCCA proposes a valuation methodology that considers most if not all products and attributes in the portfolio and recognizes the long-term nature of the utilities’ resource commitments. This proposal complies with statutory directives and guidance, while acknowledging current market limitations that prevent actual market transactions from accurately representing actual portfolio value and improves upon mechanisms and methodologies the Commission has successfully implemented in the past.

B. Portfolio Valuation to Determine Uneconomic Costs Must Recognize All Valuable Products and Attributes

The first step of portfolio valuation is to “identify products in the portfolio with value, whether explicit in the market or implicit in planning.”\(^\text{199}\) Initially, the Current Methodology recognized only two products of value in the portfolio: System RA as a measure of capacity value and the Platt’s energy forward index as a measure of “brown” energy value.\(^\text{200}\) In 2011, the Commission acknowledged that the portfolio had additional value in the form of an RPS premium above brown power, which it represents in the Current Methodology as the Green Adder.\(^\text{201}\)

CalCCA submits that there are additional products and attributes in the portfolio that are not valued by the Current Methodology, which the Commission has explicitly recognized and relied upon in the Avoided Cost Calculator. In its direct testimony, CalCCA compared the attributes valued by the Current Methodology with “the range of products and attributes either traded in the market or identified by the Commission of having unique value….\(^\text{202}\)” While there

\(^{199}\) Ex. CalCCA-1 at 2B-3:5-8.

\(^{200}\) See generally D.06-07-030.

\(^{201}\) D.11-12-018 at 17.

\(^{202}\) Exh. CalCCA-1:4-5 and Table 2A-1 at 2A-3.
are several attributes not valued in the Current Methodology, CalCCA has focused on three attributes of additional value. As discussed in Section VII.A.3, increasingly value is being attributed to GHG-free energy above the value of brown energy. In addition, Section VII.A.1 explains that the Currently Methodology recognizes only a generic capacity value, without regard for Local or Flexible RA attributes. Finally, as even the Joint Utilities acknowledge, the Current Methodology does not address ancillary services value. 203 If these values are not considered in the measures used to value the portfolio, portfolio value will be understated, overstating uneconomic costs and understating the benefits retained by bundled customers.

Evasion of simple questions during cross examination regarding portfolio attributes suggests the Joint Utilities’ awareness of this issue. Mr. Wan appeared less than clear that the three attributes in the Current Methodology fully reflect the scope of attributes and products embedded today in the utilities’ portfolios. He identified four current portfolio products or attributes: capacity, energy, ancillary services and RECs. 204 When asked whether he believed that these are the “only attributes of value in the overall portfolio,” he replied “I’m not sure I said that.” 205 He then went on to say that “[t]hat was sort of the best four, and it could be today that those are the only four. But I doubt – I highly doubt that it will remain static.” 206 He further stated that he could not think at this point in time of any other attributes, but suggested perhaps the Mr. Cushnie could “answer that further.” 207 He likewise avoided a straightforward question about GHG-free attributes, whether as a portfolio manager he equates greenhouse gas-free

203 1 Tr. 56:17-24.
204 1 Tr. 56:17-24.
205 Id. 56:12-17.
206 Id. 56:27-57:2.
207 Id. 57:10-13
energy and brown energy.\footnote{Id. 57:20-24.} As the Joint Utilities’ main policy witness, Mr. Wan’s avoidance of these questions suggest his awareness that not all portfolio value is being captured in the Current Methodology; direct acknowledgement of such a fact would cut sharply against the Joint Utilities’ position and overall proposal.

The Commission reassessed the Current Methodology in 2011 to recognize additional portfolio value in the form of the Green Adder. CalCCA asks the Commission to once again examine the utilities’ portfolios to identify all products and attributes of value. Failure to capture all portfolio value in the PCIA calculation results in a cost shift from bundled to departing load customers.

C. Value Measures Used to Determine Uneconomic Costs Must Reflect the Long-Term Characteristics and Value of the Utility Portfolio

The Joint Utilities’ PCIA-eligible portfolios are dominated by long-term investments and long-term contracts. Of the estimated $19.0 billion for PG&E, $11.5 billion (61%) represents long-term RPS commitments, $5.5 billion (29%) represents UOG investments and $2.0 billion (10%) represents other long-term contracts.\footnote{CalCCA-6, Corrected Figure 3-3.} Of the estimated $9.5 billion for SCE, $8.5 billion (90%) represents long-term RPS commitments and the remaining $1 billion (10%) represents UOG investments.\footnote{Id.} CalCCA submits that long-term resource values must be used to capture the full value of these resources – a proposition supported by Legislative mandate and Commission decisions.

As CalCCA’s witnesses explained, “[t]he value of products in the portfolio could be assessed by offering the products into the market under the same terms and conditions held by
the portfolio (i.e., offering a 20-year contract for 20 years).”\textsuperscript{211} Alternatively, they observed “the value could be assessed by looking to the value of products sold” under similar terms and conditions.\textsuperscript{212} Until early 2018, however, the Joint Utilities had made no effort to engage in forward, long-term sales of contracts or products,\textsuperscript{213} leaving only their RPS procurement to value the Green Adder and no long-term price to value capacity. In the absence of robust market prices for the sale of the same products with similar terms and conditions, “an administratively determined value used to guide utility procurement” must be used.\textsuperscript{214}

The Market Price Referent (MPR), a valuation tool used by the Commission in the RPS program, relies on long-term values. The MPR was implemented by the Commission as a result of SB 1078, which first enacted the RPS program.\textsuperscript{215} The Legislature required the Commission to “establish a methodology to determine the market price of electricity for terms corresponding to the length of contracts with renewable generators.”\textsuperscript{216} The MPR has been used for different purposes, including allocating and awarding supplemental energy payments,\textsuperscript{217} limiting a utility’s obligation to enter into contracts that exceed the MPR\textsuperscript{218} and to implement “the Legislature's mandate that the Commission determine the market price of electricity in order to evaluate the reasonableness of prices of long-term power purchase agreement (PPAs) for RPS-eligible electric generation.”\textsuperscript{219} Importantly, the Legislature mandated the development of a referent that relied on the “long-term market price of electricity for fixed price contracts,” the

\textsuperscript{211} Exh. CalCCA-1 at 2B-3:14-17.
\textsuperscript{212} \textit{Id.} at 2B-3:17-18.
\textsuperscript{213} Exh. CalCCA-3 at 3-1 to 3-5.
\textsuperscript{214} Id. at 2B-3:21 to 2B-4:2.
\textsuperscript{215} See Ex. CalCCA-110, Senate Bill 1078 (Sher, 2002) Renewable Portfolio Standard Program.
\textsuperscript{216} Id. §399.15(c).
\textsuperscript{217} Id. §399.13(c).
\textsuperscript{218} Id. §399.15(a)(1).
\textsuperscript{219} See, e.g., D.08-10-026 at 2.
“long-term ownership, operating, and fixed price fuel costs associated with fixed price electricity from new generating facilities,” and the “value of different products.” 220

While the MPR has not been updated since 2011 and its use is limited, the Commission continues to rely on it as “the best method for comparing and determining cost savings for the RPS program….” 221 Moreover, the Commission has expressly rejected the utilities’ proposals to use short-term prices to determine the value of the RPS portfolio. 222 The Commission explained its concern with the utilities’ approach:

First, few, if any resources, in any of the large IOUs’ portfolios would be considered cost-effective, including low-cost hydroelectric and nuclear resources. Second, the large IOUs’ calculations are based on short-run avoided costs, and it seems unlikely the large IOUs would be able to procure 20% or more of their portfolios accounted for the RPS program under short-term contracts. 223

CalCCA witnesses echoed this conclusion, noting that use of a short-term value for all volumes of a product in the portfolio creates distortions, stating:

This approach implicitly assumes that the utility could replace all of those long-term volumes in the current market at the then-current short-term price. Alternatively, it assumes the utility could replace all of those long-term products with short-term products and still satisfy the Commission’s expectation that the utility will provide customers a secure, reliable supply. 224

For the same reasons, use of short-run avoided costs – even the price used in the Current Methodology – is an inappropriate value measure for 100 percent of the resources in the utilities’ portfolios.

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220 SB 1078, supra, §399.15(c) (emphasis supplied).
221 Exh. CalCCA-107, The Padilla Report – Costs and Cost Savings for the RPS Program (May 1, 2018), at 12.
223 Id.
Similarly, long-term value measures are at the center of valuation for energy efficiency, demand response and distributed energy resources.\footnote{Exh. CalCCA-1 at 2B-7:6-10.} The Avoided Cost Calculator “is used to determine the benefits of resources across many Commission proceedings.”\footnote{D.17-08-022 at 3.} As CalCCA’s witnesses explained, “[t]he Calculator ‘produces an hourly set of values over a 30-year time horizon that represent costs that the utility would avoid if demand-side resources produce energy in those hours.’”\footnote{Id. (quoting Avoided Cost Calculator User Manual at 1).} In short, the Calculator reflects a valuation of a product, such as EE, based on its long-run avoided cost.

The testimony of Dr. Woychik, on behalf of UCAN, lends further credence to the need to rely on long-term measures to value long-term resources. He explained that “[t]here is always a price premium paid to reduce long-term uncertainty, which is a major part of the hedge value inherent in bilateral contracts; spot (physical) prices have little if any hedge values, so would systematically understate bilateral contract value.”\footnote{Exh. UCAN-4 at 4.} He went on to explain that “[b]ilateral contracts usually represent plant characteristics, which can be used and applied in multiple markets, and accordingly represent option value.” He observes that “[s]everal parties, including UCAN, agree that the option value of bilateral contracts should be fully monetized and included.” Ms. Kehrein, on behalf of Energy Users Forum, reinforces these observations. She concludes that “to the extent that the current method undervalues utility assets, ignores the value of optionality (hedge value), does not price all components of contract value and results in lost value,” the Current Methodology cannot prevent cost shifts between bundled and departing load.
customers. Indeed, even the Joint Utilities’ witness Mr. Wan acknowledges that optionality has value.

The Joint Utilities also seem to agree that bilateral, long-term contract values can be used to value long-term RPS resources (although the parties disagree on the source of those values). The Joint Utilities’ primary objections to using the current long-term contract measure to value its long-term RPS resources are not objections to using long-term contract values. Their objections lie in the reduction in the number of contracts that will be setting the benchmark over time, the use of prices for newly delivering contracts, rather than contracts that are executed in that year, and the presence of prices from “mandated carve-out programs that are not indicative of fully-competitive RPS markets.” None of these concerns are rooted in the use of long-term values, but instead which long-term values should be utilized. Moreover, PG&E’s calculation of the cost shift it alleges is occurring under the Current Methodology relies on a group of non-utility long-term RPS contracts. The Joint Utilities indisputably recognize that valuing long-term resources using long-term value measures is reasonable.

Despite using long-term RPS values in their own calculations of cost shifts, the Joint Utilities argue against using long-term values in assessing the value of capacity – a view that is not only internally inconsistent but hard to square with the Commission’s use of long-term values in many other contexts. As discussed in Section VII.A.1, the 2018 capacity value of $58.27 kW-year employed by the Current Methodology represents a short-run marginal capacity

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229 Exh. EUF-1 at 4:5-8.
230 Id. at 60:6-22 (Wan).
231 See infra Section VI.
232 Exh. IOU-1 at 2-17:31-36.
233 Id. at 2-16:1-4.
234 Id. at 2-16:4-9.
235 See IOU-4A and IOU-1, Table 2-2 at 2-12.
cost. The Joint Utilities contend that even this short-term value is too high, suggesting that more reasonable assessments would include the average short-term sales price for excess RA supply.\textsuperscript{236} Using these short-term prices to assess cost shifts is in conflict with the Joint Utilities’ view that “a market does not exist that would provide additional revenues to compensate for the full capacity value of post-2002 UOG resources.”\textsuperscript{237}

Finally, as CalCCA explained: “[u]sing long-term values for planning and the short-term benchmark for the PCIA can create an untenable fiction.”\textsuperscript{238} Providing an example using RA capacity, CalCCA explains that this fiction “suggests an asset valued at $110/kW-year in the planning process immediately loses value – dropping from $110 to $58 – the moment the asset becomes operational and its costs are included in the PCIA-eligible portfolio.”\textsuperscript{239} This disconnect – between valuation used to determine if a resource should be procured and valuation used to determine the ongoing value of the resource once it becomes operational – is not rational. This approach “retains the option value of the assets for bundled customers but requires departing load to pay the cost of bearing the downside price risk for bundled customers without compensation.”\textsuperscript{240} In other words, departing load customers paying for benefits that are retained by bundled customers, contrary to the requirement of §366.2(g).

The evidence and Commission practices weigh heavily in support of the use of a long-term value measure to value long-term resources remaining in the utility’s bundled portfolio. A sufficient range of values is available to recognize the long-term character of the utilities’ portfolios, as discussed further in Section VII. In the long-run, CalCCA’s SPA proposal, which

\textsuperscript{236} PG&E relies on the 2016 RA Report’s average NP-26 average price of $24.24 kW-year and, alternatively, a short-term price for excess supply sold by PG&E. \textit{See} IOU-4, line 1 columns 2 and 3.

\textsuperscript{237} Exh. IOU-1 at 5-9:21-23.

\textsuperscript{238} Exh. CalCCA-1 at 2B-7:17-18.

\textsuperscript{239} \textit{Id.} at 2B-7:18 to 2B-8:1.

\textsuperscript{240} Exh. CalCCA-1 at 2B-5:2-5.
contemplates a long-term sale of utility contracts and products in a more liquid market, should provide a reliable measure of market value for portfolio resources.

VII. CALCCA RECOMMENDS EMPLOYING A CORRECTED PCIA BENCHMARK METHODOLOGY TO DETERMINE THE PCIA UNTIL A MORE DURABLE, COMPREHENSIVE SOLUTION CAN BE IMPLEMENTED BASED ON VOLUNTARY, MARKET-BASED RESOURCE REDISTRIBUTION (Common Outline §VI)

The scope and magnitude of the problems presented by the Joint Utilities’ uneconomic portfolios defy a quick and simple solution, and a long-term vision is critical. Over the next few years, all reasonable steps must be taken to reduce the costs of existing resources, employing tools such as contract buydown and UOG securitization proposed by CalCCA in Section X. Steps must also be taken to reduce the size of the utility portfolios and redistribute supply to new LSEs that need the supply to serve their customers. CalCCA proposes to voluntarily redistribute supply through a market-based mechanism, as proposed in subsection B, below, redistribution would commence in early 2020 and conclude in late 2021. Completing these steps will result in more reliable market value measures that can be used in the valuation of any portfolio resources retained in the Joint Utilities’ portfolios. As the Commission and stakeholders move toward this end state, however, the Commission must continue to value the Joint Utilities’ portfolios to enable the identification of uneconomic portfolio costs to be allocated through the PCIA.

The record suggests the only practicable solution in the near term to mitigate the risks of cost shifts between bundled and departing load customers is modification and improvement of the Current Methodology. The Joint Utilities’ GAM/PMM proposal is not a viable short- or long-term solution; it is unlawful, devalues portfolio resources, threatens the viability of CCAs, and lacks sufficient detail to be ready for implementation in the near term, as discussed in Section VIII. Other proposals, such as TURN’s Retail Seller Subscription and Commercial
Energy’s VAAC, provide interesting ideas when considering a longer term solution, but lack sufficient detail and a comprehensive vision that can be immediately implemented. Modification of the Current Methodology provides a simple, turnkey solution that can be easily implemented for 2019 while developing the details of the SPA.

A. **Correct the Current Methodology as a Bridge to a Longer Term Durable Solution**

CalCCA proposes to correct the Current Methodology to better reflect portfolio value. Specifically, CalCCA proposes as follows:

- **Capacity.** Adopt a capacity value that more reasonably represents the underlying value of the long-term resources and sufficiently addresses the range of capacity products provided by those resources; the proposed benchmarks value capacity needed to serve bundled customers using an administratively determined, long-term proxy adopted by the Commission for other purposes and value surplus capacity using a market-derived, short-term value.

- **GHG-free Energy.** Add a GHG-free resource premium, set at the amount of the Green Adder.

- **Ancillary Services.** Augment the benchmark to recognize the value of ancillary services capability associated with certain resources.

- **Green Adder.** Modify the Green Adder to remove the DOE variable that all parties agree is unworkable and augment the value to reflect prices for long-term contracts executed by the CCAs and a more limited extent, *Platt’s PCC-1 index*. 

1. **Align Capacity Benchmark with Long-Term Capacity Value**

The Current Methodology produces a capacity value for 2018 of $58.27 kW-year, which represents a short-run marginal cost value. As CalCCAs witnesses explained, this value:

> reflects only the annual unavoidable costs of having a combustion turbine available: fixed O&M, insurance and property taxes. It does not include any

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241 CalCCA-1 at 2B-6:11-12.
242 See, e.g., 5 Tr. 1096:7-8.
long-term costs associated with capacity, such as the cost of constructing the CT.”

Fundamentally, the product valued by this short-term measure is not the same product as the long-term capacity embedded in the portfolio. In addition to failing to capture long-term value, the capacity value does not distinguish between different types of capacity products – System, Local and Flexible RA.

The Joint Utilities correctly identify the root of the challenge in valuing capacity in the utility portfolio. Referring particularly to UOG, they assert that “a market does not exist that would provide additional revenues to compensate for the full capacity value….” While parties agree on at least part of the problem the Commission faces, they disagree on the steps that should be taken to address it. The Joint Utilities propose to entirely avoid market valuation by instead allocating the bulk of RA through the GAM; combined with the CAM, approximately 64%-67 percent of all RA held in their portfolios will be allocated, not market-valued. In contrast, CalCCA proposes to rely on the interim on Commission-approved long-term capacity values to measure portfolio value, while developing an auction mechanism as a long-term approach that will allow more reliable market-based capacity valuation.

a) The Current Methodology Fails to Account for the Long-Term Value of Capacity

CalCCA witnesses concluded, consistent with the conclusions advanced in Section [X], that there is “[a]n egregious conflict” when short-term prices are used to value “attributes

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243 Id. at 2B-6:16-18.
244 See, e.g., 5 Tr. 880:9-15; see also id. at 886:24-26.
245 Exh. CalCCA-1 at 2B-6:18-22;
246 Exh. IOU-1 at 5-9:21-23.
247 Combining the Annual NQC MW values for CAM resources shown in CalCCA Confidential Rebuttal Exhibit 2B-1 with the Contract Capacity MW values for GAM and PMM resources in JU Direct Testimony Appendices F1, F2 and F3, the result is 64% for PG&E and 67% for SCE.
attached to resources acquired to meet long-term needs.”\textsuperscript{248} They further explained the problem in the context of capacity value:

Determining the value of long-term capacity held in the form of utility owned generation using the price obtained in the market for a one-year right to the capacity (or a series of one-year rights to capacity granted one year at a time) undervalues the asset by failing to recognize value in the long-term right. This disconnect is evident in comparing the Commission-approved long-term planning value for capacity of $102.31/kW-year for Southern California or $110.93/kW-year for Northern California to the current PCIA benchmark value of $58.27/kW-year or to the prices paid by the CAISO using the Capacity Procurement Mechanism of $75.72/kW-year.\textsuperscript{249}

Moreover, as noted above, this disconnect creates the “untenable fiction” that resources procured at $102.31/kW-year, consistent with planning values, immediately devalue to $58.27/kW-year when the resource becomes a part of the PCIA-eligible portfolio.\textsuperscript{250} Long-term products – in this case capacity – must be valued using long-term value measures.

The Joint Utilities only exacerbate this disconnect, ignoring any long-term value of capacity by focusing solely on the short-term RA prices reported to the Commission in constructing their cost shift argument.\textsuperscript{251} However, long-term costs for capacity are not recovered in those markets. Construction and ongoing capital costs are recovered via a number of other means: bilateral contracts; CAM cost recovery; traditional rate recovery; RMR contracts; CPM contracts and asset sales. The Joint Utilities ignore the potential to make use of these cost recovery tools for their long-term embedded costs, greatly underestimating the revenues they could receive if they were to sell their capacity in anything but the spot RA market.

\textsuperscript{248} Exh. CalCCA-1 at 2B-4:3-6.
\textsuperscript{249} Id. at 2B-4:6-14.
\textsuperscript{250} Id. at 2B-7:17 to 2B-8:1.
\textsuperscript{251} Exh. IOU-3A, AppE-1:74 and AppE-2:74.
Long-term capacity has value that differs from the value of RA sold in the market for a month or even a year.\(^{252}\) Long-term capacity resources provide “optionality” value. As CalCCA witness Hoekstra explained:

> [A]s a general matter, the resources and assets in the PCIA-eligible portfolios are long-lived assets with significant ability to respond to conditions in the market in terms of their output. And ownership and control of assets gives the beneficiary the ability to manage the operation of those resources. In a power purchase agreement, having the ability to terminate, extend, adjust price, things like that, creates optionality.\(^{253}\)

He went on to observe that long-term contracts also provide a hedging value:

> Hedging corresponds more to hedging risk exposure. So to the extent that someone buying power in the market is exposed to market prices, obtaining an offsetting hedge that reduces that exposure perhaps by creating long-term supply, entering into long-term transactions with price certainty, that would tend to offset and mitigate that risk. That would be a hedging value.\(^{254}\)

Mr. Hoekstra further explained that a “purchaser of power may be willing to commit to a long-term fixed price over a defined term to gain certainty as to the price it will pay, budgetary certainty, cash flow certainty, things like that.”\(^{255}\) The value of the premium would be realized by “gaining that certainty.”\(^{256}\)

Dr. McCann followed on this point with an example based on PG&E’s 2016 draft renewable energy procurement plan. Reading from the plan, he stated:

> PG&E’s fundamental strategy for mitigating RPS cost impacts is to balance the opposing objectives of, one, delaying additional RPS-related costs until deliveries are needed to meet a physical compliance requirement, and two, managing the risk of being caught in a seller's market where PG&E's potentially high market basis, potentially high market prices in order to meet near-term compliance deadlines. When these objectives are combined with general need to manage overall RPS portfolio volatility based on demand and generation uncertainty,

\(^{252}\) See supra, Section VII.A.1; see also 5 Tr. 13-19 (Hoekstra).

\(^{253}\) 5 Tr. 899:20-900:1 (Hoekstra); see also 5 Tr. 1093:25-1094:22 (Woychik).

\(^{254}\) 5 Tr. 900:8-16 (Hoekstra).

\(^{255}\) 5 Tr. 900:21-25 (Hoekstra).

\(^{256}\) 5 Tr. 900:27-901:2 (Hoekstra).
PG&E believes it is prudent and necessary to maintain an adequate bank [that's the RPS bank] through the most cost-effective means available.\(^{257}\)

He observed that “this was the basis for maintaining high cost RPS contracts in its portfolio and not disposing of those contracts.”\(^{258}\) CalCCA witness Marrinan added that one of the benefits that come with holding long-term resources is information and control over the resource, which are not conveyed through short-term attribute allocation.\(^{259}\) Allocation of resource attributes not coupled with information and control regarding the volume, timing and dispatch of those resources does not constitute a hedge but rather introduces uncertainty and volatility into the portfolio of the recipient CCA or other LSE.\(^{260}\)

Dr. Woychik, on behalf of UCAN, further discussed the optionality embedded in long-term resources. In response to ALJ Roscow’s questions on the “receipt” method of valuing resources, he reinforced the differences between short-term and long-term products.

Now, we're going to try to apply under the utilities proposal, a short-run [marginal] cost to a long-run product, which had a lot optionality, and then you're going to say it's only value is just energy, very narrow, a very, very limited part of the optionality, in fact, a narrow slice of it, and say that's an appropriate value for the energy component. I think that's the mismatch….\(^{261}\)

He suggests “there’s long-run value to that in hedging and understanding you’re going to play that, but nobody’s discussing it except the CCA expert witness panel….“\(^{262}\)

Additional capacity value for long-term resources is also demonstrated in UOG operations, which appear under the Current Methodology to be operated uneconomically.

CalCCA does not contend that these resources are uneconomic to operate; instead, CalCCA

\(^{257}\) 5 Tr. 901:10-902:1 (McCann) (quoting PG&E’s draft renewable energy procurement plan at page 19).

\(^{258}\) 5 Tr. 902:2-5 (McCann)(quoting PG&E’s draft renewable energy procurement plan at page 19).

\(^{259}\) 5 Tr. 904:28-905:2, 16-17 (Marrinan).

\(^{260}\) Exh. CalCCA-3 at 4-13:4-9, 5 Tr. 905:3-23 and 906:5-10, 15-26 (Marrinan).

\(^{261}\) 5 Tr. 1096: 21-24 (Woychik).

\(^{262}\) 5 Tr. 1097:1-8 (Woychik).
contends that the MPB understates the value of capacity for these resources, causing this
distortion. CalCCA witness Kinosian observed:

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.263

Mr. Kinosian concluded from these data that “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.”264

Using Diablo Canyon as an example, he estimated that an $85/kW-year capacity value must be
assumed to justify the facility’s operation.265 He similarly pointed out that “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.” 266 SCE’s Palo Verde facility likewise shows operating costs that are
“above SCE’s proposed energy and RA” benchmark.267

Administratively determined capacity values recently approved by the Commission are
readily available to capture the range of value in long-term capacity, as discussed more
extensively in Section VII.A.1. CalCCA witness Hoekstra observed that the Commission’s
Avoided Cost Calculator provides such values. He stated: “[t]he Calculator values long-term
capacity at $102.31/kW-year for Southern California or $110.93/kW-year for Northern
California, compared with the $58.27/kW-year adopted in PG&E’s and SCE’s 2018 ERRA for

263  Exh. CalCCA-3 at 2B-6:2-9 and Table 2B-1.
264  Id. at 2B-6:10-12.
265  Exh. CalCCA-3 at 2B-7:3-5.
The values selected from the Calculator are for calendar year 2018, drawn from a model that provides annual values for calendar years 2016-2047. Finally, CalCCA’s witness Hoekstra pointed out that the Current Methodology’s capacity value even “understates actual short-term values reflected in the market.” In particular, the CAISO CPM has produced short-term RA prices of $75.72/kW-year. This value represents the value of purchases “to correct for the LSEs’ collective failure to procure sufficient RA for the 2018 year-ahead compliance filings.” He explained further: “The price is not a planning value; it provides a transparent and variable price benchmark that accurately reflects actual transactions based on the near-term supply and demand balances for RA in both Northern and Southern California.”

b) The Current Methodology Fails to Distinguish Among System, Local and Flexible RA Capacity

The Current Methodology’s short-term RA benchmark recognizes only one generic “flavor” of RA. In today’s market, however, there are three types of RA products, including System, Local and Flexible RA, and the market is ever-changing. The prices for these products may differ, even in the short run, as evidenced by the 2016 RA Report. Consequently, relying on a single, short-term generic RA value cannot adequately value the full range of RA products embedded in the Joint Utilities’ portfolios.

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268 Exh. CalCCA-1 at 2B-7:14-16.
269 See id. at 2B-4, n. 2 and 2B-9, n. 7.
270 Id. at 2B-8:4-5.
271 Id. at 2B-8:3-17.
272 Id. at 2B-8:8-11.
273 Id. at 2B-8:11-14.
274 3 Tr. 521:4-6 (Barkovich) (“We do have the three flavors of resource adequacy, which are system, local, and flexible.”); Ex. CalCCA-1 at 2B-6:18-22.
275 See Exh. CalCCA-108, Figure 6 at 26. Note, however, that timing of sales may affect price more than the type of RA. See, e.g., CalCCA-103C, Fourth Quarter 2017.
Dr. Barkovich testified to the unique challenges of valuing Local RA. Using PG&E’s Humboldt plant as an example, she explained that this Local RA resource “is needed for local reliability and it isn’t cheap.”\textsuperscript{276} She observes that the CAISO has engaged in procurement over the last year to address shortfalls in Local RA procurement\textsuperscript{277} and concludes that using system RA to value the above-market portion of a local RA resource is “problematic.”\textsuperscript{278}

Dr. Barkovich also suggested uncertainty about valuing Flexible RA. She noted that the product today is “not showing much of a premium above system RA in the market”\textsuperscript{279} although she points to growing conditions where this may change.\textsuperscript{280} Dr. Woychik reinforced the message of change:

\begin{quote}
We certainly don't have all the flexible ramping capacity we need. That's another product. We don't have the flexible ramping product. The flexible ramping product is the tradable new product that Cal ISO's coming out with and there's three varieties of it, basically, in terms of time: 15 minute, five minute, and close to realtime.\textsuperscript{281}
\end{quote}

Finding a reasonably representative value for short-term, let alone long-term, Flexible RA presents a challenge.

In an ideal world, long-term market values for all three flavors of RA would be available to reasonably value capacity in the Joint Utilities’ portfolios. Unfortunately, no long-term market values for capacity are available. Moreover, short-term values for each type of capacity, as Dr. Barkovich and Dr. Woychik testified, are difficult if not impossible to determine under changing conditions. For these reasons, CalCCA proposes “to avoid the complexities of valuing

\begin{itemize}
\item \textsuperscript{276} 3 Tr. 525:18-22 (Barkovich).
\item \textsuperscript{277} 3 Tr. 521:20 – 522:3 (Barkovich).
\item \textsuperscript{278} 3 Tr. 525:10-12 (Barkovich).
\item \textsuperscript{279} 3 Tr. 526:4-17 (Barkovich).
\item \textsuperscript{280} 3 Tr. 526:4-6 (Barkovich).
\item \textsuperscript{281} 5 Tr. 1095:2-13 (Woychik).
\end{itemize}
each product” and recommends the use of a single, long-term capacity value282 as the most practicable and pragmatic solution.

c) The Current Methodology Should Be Revised to Reflect a Long-Term Value for Capacity Remaining in the Portfolio and a Short-term Value for Surplus Supply

Long-term capacity that provides value to bundled ratepayers, beyond simply meeting a one-year RA compliance obligation, should be valued using a long-term value measure, as explained in Section VI. While no market for long-term capacity exists to produce an explicit price referent, the Commission and the utilities “continue to use administratively determined long-term market values for making procurement and management decisions,”283 which could be used as proxies. In particular, the Commission has invested substantial time and resources to determine a long-term capacity value using its Avoided Cost Calculator.284 Although this value measure was developed for purposes evaluating the cost-effectiveness of procurement of EE, DER or DR, the Calculator is a valuation methodology that assesses the capacity value of these resources using an avoided cost methodology. CalCCA thus proposes to apply the Calculator capacity value for the year in which the portfolio is being valued to all capacity retained in the portfolio to serve bundled customers.285

Arguably, even surplus capacity held in the utility portfolio and sold in the market has long-term value if it serves as a hedge for bundled customers. For example, retaining surplus capacity in the portfolio mitigates the risk that the utility may have to buy RA at higher prices in the event of unexpected unit outages or generators being forced out, changes in regulations or

283 Id. at 2B-7:4-6.
other reasons.\textsuperscript{286} It also bears considering that such a buffer mitigates the cost recovery risk for shareholders by mitigating the risk of disallowance in the management of RA resources.\textsuperscript{287}

2. **Adopt a Benchmark to Reflect Ancillary Services Value**

The Joint Utilities “hold capacity in their portfolios that provides or is capable of providing ancillary services to support their bundled load or to sell into the market.”\textsuperscript{288} The Current Methodology does not account for the value of ancillary services.\textsuperscript{289} The Joint Utilities appear to recognize this methodological oversight implicitly in providing for the allocation of Ancillary Services revenues under the PMM.\textsuperscript{290}

The primary issue in controversy is the valuation of Ancillary Service capability. The Joint Utilities, consistent with their view that only “realized” revenues can be used to value products or attributes in their portfolios, would value the capability or services using the actual revenues received for Ancillary Services sales.\textsuperscript{291} CalCCA, in contrast, proposes to use the Ancillary Services values derived in the Avoided Cost Calculator, currently $2.81/kW-year in Northern California and $3.46/kW-year in Southern California.\textsuperscript{292} CalCCA recommends applying the value to “the resources held in the PCIA-eligible portfolio that provide ancillary services,” identifying those resources by the presence of Automatic Generation Control, which enables these resources to follow load.\textsuperscript{293} The effect of this modification is to increase the value

\begin{footnotesize}
\begin{itemize}
\item 286 Exh. CalCCA-102-C at 3-4.
\item 287 \textit{Id.} at 2.
\item 288 \textit{Id.} at 2B-9:9-10.
\item 289 \textit{Id.} at 2B-9:10-11.
\item 290 Exh. IOU-1 at 4-3:13-20.
\item 291 Exh. IOU-1 at 4-3:13-20.
\item 292 Exh. CalCCA-1 at 2B-9:14-16.
\item 293 Exh. CalCCA-1 at 2B-9: 18-21.
\end{itemize}
\end{footnotesize}
recognized in PG&E’s 2018 portfolio by an estimated $10.1 million and $10.4 million for SCE. 294

3. Adopt a Benchmark to Reflect the Market-Recognized Premium for GHG-Free Energy

CalCCA proposes to augment the existing portfolio valuation measure to include an explicit premium above brown power prices for GHG-free resources.295 As CalCCA witness Kinosian testified: “GHG-free generation carries a premium in today’s market, although no reliable published market index values for this generation exist.”296 The record supports this conclusion, calling for the addition of a GHG-free resource premium to GHG-free resources in the Joint Utilities’ portfolios.

With the state (and many customers) highly focused on 2030 GHG reduction goals, the Joint Utilities are increasingly focusing their marketing and public relations strategies on GHG-free resources, regardless of whether the GHG-free resources are RPS-eligible. “Clean Energy Solutions” on PG&E’s website advertises the GHG-free characteristics of various resources. It states: “Nearly 70% of the electricity we provide to our customers comes from sources that are greenhouse-gas free.”297 Under “Fighting Climate Change,” another tab on the website, PG&E emphasizes that “[a]s a provider of gas and electricity to millions of Californians, PG&E works hard to manage greenhouse gas emissions.”298 Similarly, SCE’s whitepaper, The Clean Power and Electrification Pathway, focuses on GHG reductions.299 Its “Preferred Pathway” identifies

295 Id. at 2B-10 – 2B-11.
296 Id. at 2B-10:8-9.
299 Exh. CalCCA-117.
as a goal “80% carbon-free electricity supported by energy storage”; focus on renewable resources specifically takes second stage.

One of the drivers for this value adder, Mr. Kinosian notes, “is its marketing value when shown in the LSE’s Power Content Label.” Public Utilities Code §398.4(a) requires: “[e]very retail supplier that makes an offering to sell electricity that is consumed in California shall disclose its electricity sources for the previous calendar year.” Under Energy Commission regulations, the utilities, CCAs and ESPs must separately identify the percentage of energy they deliver to customers attributable to generation from each type of renewable, coal, large hydroelectric, natural gas-fired, nuclear and other sources. The PCLs are available to the public, enabling customers to judge potential service providers by the relative environmental friendliness of their portfolios. For 2016, PG&E’s portfolio included 69% GHG-free resources, thus enabling the “clean energy” marketing representations on its website. Power & Water Resources Pooling Authority, based on its PCL, appears to offer a low-carbon product, including 73% hydro energy and 27% from renewable resources.

PG&E’s testimony in the Diablo Canyon Power Plant proceeding likewise validates a premium value for GHG-free resources. PG&E proudly stated in its testimony:

PG&E’s portfolio of electric resources has historically been one of the lowest emitting in the United States. At least one-half of the electricity supplied to PG&E’s bundled electric customers has consistently been GHG-free.

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301 Exh. CalCCA-1 at 2B-10:9-10.
302 See Exh. CalCCA-118 (providing examples of Power Label Content disclosures for PG&E, SCE, and several other retail suppliers).
303 Id. PG&E 2016 Power Content Label.
304 Id. Power & Water Resources Pooling Authority 2016 Power Content Label.
305 Exh. IOU-118, Chapter 3 at 3-11.
It claimed that a “key element” of its proposal was that “it recognizes the value of GHG-free nuclear power as an important bridge over the next eight to nine years.”  PG&E explained that in filling its Energy Efficiency “tranche” of GHG-free replacement resources, “[o]ffers will not be accepted unless they are below a RPS eligible resource cost cap” of $82 kWh in 2016 dollars. As Mr. Kinosian explained, “PG&E stated the GHG-free generation from Diablo Canyon was worth considerably more than brown power, amounting to $85/MWh in 2018 dollars.”

Other evidence of GHG-free resource values can be found in the summary of “External Solicitations in Which PG&E Participated (2016-2018).” Of the 17 solicitations PG&E identifies, four sought proposals for energy products, with the remainder requesting proposals for RA products. Among those requesting proposals for the sale of energy, 100% requested proposals for “carbon-free” energy separate and apart from other forms of energy.

Finally, the Joint Utilities agree with CalCCA that there are no reliable published market index values” available for GHG-free resources. They also acknowledge, however, that other market participants have placed a value on GHG-free energy. The Joint Utilities how GHG-free transactions “are commonly traded among market participants across the Western Interconnection via voice brokers.” Explaining the formula used to calculation the “’premium’ paid for GHG-free energy versus unspecified energy (e.g., brown power), they

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306 Exh. IOU-118, Chapter 3 at 3-1:35-36.
307 Exh. IOU-118, Chapter 4 at 4-5:20-21.
309 Exh. IOU-3, Table 3-3 at 3-11.
310 See id. Table 3-3 at 3-11, Rows 4, 6, 7 and 13.
311 Exh. IOU-3 at 2-25, n.73.
conclude that at a GHG allowance price of $14.75/metric ton, “the potential value of GHG-free energy would be $6.14/MWh,”\textsuperscript{312} They further observe:

Notably, on February 14, 2017, Sonoma Clean Power (SCP) estimated that its carbon-free “premium above the cost of general energy” was less than $2/MWh. Additionally, the Short-Term Cost of Service Model included in the City of San Diego’s CCA Feasibility Study, published July 2017, estimated the cost of a carbon-free adder to be $3.50/MWh.\textsuperscript{313}

It should also be noted that California provides a statutory premium for the Joint Utilities for GHG-free power, including that from large hydroelectric resources. Section 454.3 provides for a premium up to a full 1 percent on a utility’s rate of return for investment in clean resources, mentioning in particular existing hydroelectric facilities.\textsuperscript{314} This and other record evidence explained above make clear that there is no question whether there is a GHG-free premium embedded in the Joint Utilities’ portfolios, but the magnitude of that premium.

The Commission, in light of this evidence, cannot reasonably conclude that GHG-free energy carries no premium in the market. To do so would equate GHG-free energy with brown power – an equation that is anathema to California’s aggressive GHG reduction goals. Thus, the only questions are the appropriate premium to apply to GHG-resources and which GHG-resources should be valued using this premium.

CalCCA’s testimony proposed to apply the RPS premium – $24.16/MWh for PG&E and $25.11/MWh for SCE – to all of the IOUs’ GHG-free generation.\textsuperscript{315} The impact of this change would be an increase in portfolio value of an estimated $654.6 million for PG&E and $218.5

\textsuperscript{312} Id.
\textsuperscript{313} Exh. IOU-3 at 2-25:11-15.
\textsuperscript{314} Section 454.3(a) provides for a return premium for investment in a facility “designed to generate electricity from a renewable resource, including, but not limited to, solar energy, geothermal steam, wind, and hydroelectric power at new or existing dams…."
\textsuperscript{315} Exh. CalCCA-1 at 2B-11:13-19.
million for SCE.\textsuperscript{316} Indeed, PG&E’s testimony in the Diablo Canyon proceeding and the Joint Utilities’ rhetoric surrounding GHG-free energy support this solution.

4. \textbf{Correct the Green Adder by Removing the Outdated Department of Energy Benchmark Component}

CalCCA proposes that the “Green Adder” be corrected by removing the unsupported and inaccurate Department of Energy referents in the calculation. The methodology and data source adopted in 2011 when the Green Adder was initiated is no longer effective or available. The source of the pricing information, which comes from programs identified in a database from NREL, is unclear.\textsuperscript{317} In many cases the information is out-of-date, inaccurate or irrelevant.\textsuperscript{318} The DOE information also systematically undervalues the retail green premium, in CalCCA’s calculations by at least $10/MWh.\textsuperscript{319} If the DOE referents were removed, the 2018 PCIA benchmark value would be increased by an estimated $67 million for the PG&E portfolio and $90.3 million for the SCE portfolio.\textsuperscript{320}

Added to the PCIA benchmark in 2011,\textsuperscript{321} the Green Adder was intended to add the market value of renewable resources into the MPB calculation.\textsuperscript{322} In order to do so, the Commission stated its intent that the Green Adder should reflect “prices paid by buyers and sellers in recent transactions for delivery of RPS compliant power in California for the forecast

\textsuperscript{316} \textit{Id.}
\textsuperscript{317} \textit{Id.} at 2B-12.
\textsuperscript{318} \textit{Id.} at 2B-13; see Testimony of Richard J. McCann, Ph.D. on Behalf of Sonoma Clean Power Authority (Revised), A.17-06-005, August 28, 2017, at 11-13.
\textsuperscript{319} \textit{Id.} at 2B-14:13-14.
\textsuperscript{320} \textit{Id.} at 2B-14:8-10.
\textsuperscript{321} D.11-12-018. The Commission also revised the Capacity Adder, eliminated CAISO load-based costs in calculating the PCIA, replaced the use of a flat MPB weighting with a weighting based on the historical utility bundled load profile, and other DA-related changes.
\textsuperscript{322} \textit{Id.} at 10
year.” The Commission chose to rely primarily on the utilities’ costs of procuring renewable resources, weighted at 68% of the benchmark, supplemented by “western regional renewable energy contract premiums published by U.S. DOE” for the remaining 32%. The DOE information is taken from survey of reported renewable energy contract premiums in the western United States compiled by the National Renewable Energy Laboratory.

However, the source of the pricing information, which comes from programs identified in a database from NREL, is unclear and of questionable utility. The NREL page on Voluntary Green Power Procurement does not provide any detailed information on individual programs. In communications with NREL staff, they stated data on individual programs has never been distributed. Moreover, some of the programs that have been relied upon in ERRA proceedings are now defunct and out of date. Data on the list indicates that it has not been updated since 2015 or perhaps even earlier. In all, CalCCA has identified at least 19 discrepancies out of the 89 programs listed, excluding consideration of other programs that may have been since added. Thus, there is simply no guarantee that the utilities are collecting data from all of the applicable programs across the western United States, or that the DOE website can constitute the third-party source the Commission no doubt intended.

Finally, the green power premium is calculated incorrectly. The premium is calculated against generation mixes that contain a varying mix of brown and green power, unlike the utility RPS Premium which measures 100% green versus approximately 100% brown power. The DOE Adder therefore undervalues the retail green premium.

323 Id. at 17.
324 Id. at 22.
325 Eric O'Shaughnessy, NREL, email communication, May 25, 2017.
For these reasons, the current DOE/NREL portion of the green adder benchmark should be eliminated, and the benchmark should reflect only the average of utility RPS procurement costs. Procurement by three large utilities, each of them direct participants in a fully developed renewables market, should reflect a reasonable market value.

With this correction, the Green Adder used in the Currently Methodology should provide a reasonably representative value until the SPA can be fully integrated to provide an alternative value measure. Approximately “600 MW of new RPS resources will begin delivery to PG&E, 2,300 MW to SCE and 134 MW to SDG&E” over the next few years. If, instead, deliveries became too limited to produce a reliable value, the Green Adder could be blended on a limited basis (e.g., 25%) with the Platt’s PCC 1 index.

B. Adopt a Voluntary, Market-Based Solution That Will Reduce Utility Portfolio Size and Redistribute Resources, While Producing More Reliable Value Measures

Nearly all parties recognize that the Current Methodology is not a long-term durable solution for the problems of stranded costs, “double procurement” and an untenable mismatch between the Joint Utilities’ portfolio supply and demand. A more comprehensive solution must substantially slow utility procurement, reduce portfolio costs, maximize portfolio value and redistribute supply to avoid an untenable mismatch between utility supply and demand. In order to prevent cost shifts as required by statute, an effective solution must produce a valuation that recognizes the full benefit imputed by market forces for these long-term supply resources where resource control, resource information transparency, dispatch and all product attributes flow to the party paying the fixed and variable cost burden of the asset. CalCCA’s proposal is the only one submitted in this proceeding that achieves, let alone even attempts to achieve:

327 Exh. CalCCA-3 at 2B-10:14-16.
Proposals to reduce portfolio costs through securitization and active portfolio management;

The voluntary, long-term reallocation of portfolio resources to the LSEs that put the greatest value on control over those resources to serve customers; and

The maximization of long-term resource value and a clear path to avoid wasting value inherent in the portfolio, such as the 10+ year RPS procurement attribute and the value of GHG-free energy.

CalCCA recognizes, however, that a durable solution will take time, requiring further analysis and planning by the Commission and stakeholders. In this context, CalCCA advances for further development a Staggered Portfolio Auction mechanism, which uses market forces to redistribute supply and provide more reliable valuation measures for the utilities’ portfolios.

1. CalCCA’s Proposed Staggered Portfolio Auction is a Voluntary, Market-Based Portfolio Allocation Mechanism to Redistribute Utility Supply

CalCCA’s SPA allows all LSEs (IOUs, CCA, DA providers) to “voluntarily bid to procure resources, based on the value they and their customers place on these resources and their alternatives, to best serve their respective customer classes.” Under the SPA, the market participant placing the highest value on the Joint Utility assets would prevail in the auction. This approach minimizes stranded costs and the need for PCIA recovery by maximizing the derived value of the assets.

CalCCA proposes that the utilities be required to offer 100% of the PCIA-eligible output of their RPS-eligible PPA, GHG-free resources, and energy storage resources (Auction Resources) in multiple tranches. These tranches would then be auctioned over time to other utilities, CCAs, ESPs, and other market participants. Auctions would be open to all market participants on a voluntary basis. For illustrative purposes CalCCA proposes that auctions be
held quarterly for two years, beginning in January 2020. This should allow time for Commission consideration and stakeholder input. CalCCA has provided projected volumes of the Auction Resources for the 12-year period from 2019-2030.

Assuming a 2-year schedule, the auctions could be accomplished by holding eight separate auctions, each offering a diverse group of contracts to the market, with varying sizes, terms, locations and technologies offered. PPA resources would be auctioned by creating smaller marketable contracts out of the utilities’ larger, long-term PPAs. These smaller volume contracts would generally mirror the original utility contracts with respect to term and type of products offered, but in smaller quantities. These smaller, and therefore less expensive, contracts would be attractive to a broad group of bidders. GHG-free UOG resources and RPS-eligible UOG resources such as small hydro and energy storage would be auctioned as blocks of energy and associated RA capacity. CalCCA has proposed tranches of 50 MW each, with a term and product attributes dependent on the energy in that particular tranche. For example, energy from certain resources may not be available after a certain date due to licensing constraints.

Although of course subject to the Commission’s preference, under CalCCA’s proposal the highest winning all-in bid in each tranche would set the market-clearing price for all of the products and attributes offered in that tranche. CalCCA proposes the Commission set a minimum bid price based on short term market prices, broker quotes or other metrics, and consider whether a limit should be placed on participant concentration, to allow for maximum liquidity of the market. It is assumed that the utilities would be active participants in the market given the requirement for them to sell 100% of their RPS-eligible Energy and GHG-free Energy

328 Exh. CalCCA-1 at 4-5:10.
329 Exh. CalCCA-3 at 4-2.
in the portfolios, and would bid aggressively to ensure receipt of some portion of these assets for their bundled customers. Because the utilities will be present as both the seller and potential buyer in many cases, CalCCA stresses the importance of Commission involvement in the design and implementation of any auction. Of course, the Commission could engage third-party consultants to aid it in developing auction mechanics, and in administering the auctions themselves.

2. The SPA Provides More Reliable Valuation Measures for the Utilities’ Portfolios

The SPA not only maximizes the monetary value of the assets, but it significantly increases the value of those assets to the LSEs paying the fixed and variable costs associated with those assets. First, this approach provides the buyer with access to the full range of product attributes; the attributes proposed to be allocated and liquidated by the Joint Utilities represent only a subset of the attributes.330

Second, it provides the buyer with a product that can reasonably be considered a hedge to its load obligations. Product attributes that are allocated or liquidated in the short-term market by the utility, such as would occur under the GAM/PMM proposals, would leave all dispatch control of and information about these positions with the utility. The LSE receiving the allocation of attributes or the CAISO settlement of spot value does not have detailed information regarding hourly dispatch volumes or cost and lacks the requisite detail to rely on these allocations or settlements as even a short-term hedge to its load obligation and that does nothing to eliminate the need to procure long term resources. This proposed after the fact dump of

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attributes does nothing but introduce uncertainty and volatility to the recipient LSE’s portfolio which represents a real and tangible cost shift to the subject LSE.\footnote{Id. at 4-13.}

Third, the SPA provides control over the asset lives selected by the buyers so that they match the term of buyer load obligations and they meet the 10-year commitment requirement for 65% of RPS resources mandated by statute implemented by SB 350.\footnote{Cal. Pub. Util. Code §399.13(b).} Short-term liquidations and allocations of attributes are not a reasonable hedge for a long-term load commitment nor do they provide for the LSE’s requirement to contract for 10-year resources.\footnote{Id.} Double procurement would continue under the Joint utility proposal.\footnote{Exh. CalCCA-3, at 4-14.}

Fourth, the SPA provides control over the asset over the long term. The buyer can control the choice to retain or sell it in the future to match the ongoing needs of the buyer’s portfolio.

Finally, the SPA, unlike the GAM/PMM, complies with §366.2(a)(5). CCAs retain procurement autonomy to determine the contents of the portfolio used to serve its customers.\footnote{Exh. CalCCA-3, at 4-8.} Consequently, CCAs are free to procure resources that meet the local needs and choices of the communities they serve.

3. The SPA Provides the Commission with the Ability to Structure the Details of the Auction Process to Ensure Efficiency and Optimal Outcomes

While CalCCA provides a “broad structural and conceptual framework”\footnote{Exh. CalCCA-1, at 4-2:9.} for an auction that would provide for the benefits outlined above, it also recognizes that auctioning these

\footnotesize{
331 Id. at 4-13.
333 Id.
334 Exh. CalCCA-3, at 4-14.
335 Exh. CalCCA-3, at 4-8.
}
resources represents a significant undertaking that should be taken on with the full review and approval of the Commission. Specifically, CalCCA recommended:

The Commission, after considering stakeholder input, will determine [the] auction structure and criteria and have final approval of agreements arising from the SPA. Details will be determined based on the Commission’s preferences, which may involve implementation by an independent auction manager, review by an Independent Evaluator, PRG, and/or other stakeholder process.\(^{337}\)

Further, CalCCA recognizes that adjustments to the process could improve outcomes and recommends that the auctions take place in stages to anticipate and allow for flexibility in the process. CalCCA initially suggests quarterly auctions during 2020 and 2021, with 12.5% of the portfolio included in each auction, offering “a diverse group of contracts to the market, with varying sizes, terms, locations, and technologies.”\(^{338}\)

There are several reasons for this recommended structure:

- **Increase participation and liquidity.** Multiple auctions would involve a narrower set of specific contracts and/or smaller volumes than a single comprehensive auction. This structure will likely be more attractive and/or more manageable for a greater number of bidders and thus would lead to greater participation and higher prices.

- **Flexibility to adjust for new events or information.** The quarterly auction approach allows for greater ability to adjust the specific contracts, quantities, and/or products being auctioned to account for new market developments, State policy changes, and/or reliability needs that affect LSEs’ procurement practices.

- **Reduce risks of anomalous bidding behavior.** Multiple auctions over a period of two years would reduce the impacts of strategic bidding, gaming or other unforeseen behaviors by auction participants that would jeopardize the integrity of the auction process.

- **Mitigate effects of anomalous market conditions.** Multiple auctions spread out over time would average out price volatility, and therefore reduce the impacts of

\(^{337}\) Exh. CalCCA-1 at 4-5:7-12.

\(^{338}\) Exh. CalCCA-1 at 4-7:16.
unforeseen and temporary price increases or decreases compared to a single comprehensive auction happening once.\(^{339}\)

4. **The SPA Provides the “Sales Receipt” the Joint Utilities Claim to Need to Avoid Cost Shifts and is the Only Recommended Alternative Where the Receipt Matches the Product that the CCAs are Paying for Through the PCIA**

CalCCA fundamentally disagrees with the assertion made by the Joint Utilities and TURN that the Commission must have a “sales receipt” for actual revenues from the sale of surplus power supplies to calculate the PCIA. The “sales receipts”, or short-term market prices, do not reflect the ranges of products and attributes in the portfolio, nor their long-term value. In other words, the sales receipts are for the wrong products.

It bears noting, however, that in stark contrast to the GAM/PMM short-term product proposal, the proposed SPA provide can provide a relevant “sales receipt.” Auctioning the portfolio resources on a long-term basis will produce receipts that reasonably represent the values the broader range of long-term attributes that are actually contained in the PCIA-Eligible portfolios. The SPA is the only proposal before the Commission that values the relevant products or seriously attempts to realize their full value.

5. **A Residual Portfolio May Remain and Will Require Further Consideration**

The Joint Utilities have accurately pointed out that there may be a Residual Portfolio of resources left if (1) not all auctioned resources are sold or (2) more than the utility forecast for departing load is realized. CalCCA proposes to address the Residual Portfolio by modifying the volumes offered in the eight quarterly auctions and/or 2) holding additional auctions beyond the initial eight quarterly auctions.

\(^{339}\) Exh. CalCCA-1 at 4-7:11 to 4-8:10.
During the initial 2 year quarterly auction period, CalCCA proposes that all resources sold be valued at the auction clearing price for purposes of calculating the PCIA. Resources that have not yet been sold will continue to be valued at the Corrected Benchmark price until sold.

To the extent that the Utilities’ dual gloom and doom scenario of high departing load and high auction prices materializes, and further, the scenario unfolds whereby the utilities have underforecast departing load and are forced to buy back portfolio resources at a higher cost than book value, the overall impact to portfolio value would be overwhelmingly positive. The revenues from the auction would flow back to all PCIA responsible customers, offsetting the cost of the resources purchased in the auction. This balancing of PCIA cost responsibility and offsetting auction revenue benefit would carry to any Residual Portfolio auctions that may be needed.

6. The SPA Complements the Commission’s Integrated Resource Planning Process and Support Environmental Policy Goals

The SPA provides the best option for the Commission to fully leverage the long-term supplies of RPS-eligible and GHG-free energy in the utilities’ PCIA-Eligible portfolios to facilitate the IRP process and the achievement of California’s environmental goals. The auctioning of RPS-Eligible and GHG-Free resources to the market participants that value them most would maximize the portfolio value by allowing bidders to buy long-term products and providing supply to the highest bidder. The direct conveyance of RPS-Eligible energy purchased under the utilities’ existing PPAs supports compliance with the SB 350 requirement for 65% procurement through commitments of 10-years or longer. No other Party’s proposal in this case even attempts to support these key imperatives.

CalCCA’s modeling indicates that the RPS-Eligible and GHG-Free resources proposed for the SPA captures approximately 91% of the combined PG&E and SCE PCIA-Eligible
portfolios for the 12-year period from 2019-2030 with (whether measured by generation output, total costs or stranded costs.\textsuperscript{340} Thus, the scope of the proposed SPA is correctly defined to focus on the driving value from the most important and highest valued components of the portfolios. The implementation timeline and the forward procurement horizon of the SPA proposal is intended to align with the IRP process pending in R.16-02-007, allowing long-term LSE commitments to procure these resources beginning by 2020 and lasting at least 10 years forward to 2030 and beyond.

CalCCA’s SPA proposal excludes fossil-fueled generation resources because there are good reasons to do so: a) fossil resources represent only about 5% of the generation output, costs and stranded costs in the utilities’ PCIA-Eligible portfolios over the 2019-2030 period.\textsuperscript{341} Consequently, fossil resources are not a major driver of value or stranded costs in the portfolio which lies predominantly in the RPS-Eligible and GHG-Free resources; and b) the majority of fossil resources are expected to drop out of the PCIA-eligible portfolios soon because of the 10-year cost recovery rule and/or because the relevant PPAs expire. However, fossil contributes about 14% of the RA Capacity in the combined PG&E and SCE 2019-2030 PCIA-Eligible portfolio but this contribution is concentrated in the next few years—it is projected to be nearly completely rolled off from the SCE portfolio by 2021 and from the PG&E portfolio by 2023.\textsuperscript{342} CalCCA’s proposal appropriately permits separate consideration of the reliability-related and RA Capacity-related issues associated with this contract roll-off in the Commission’s IRP or RA proceedings where they are more appropriately addressed.

\textsuperscript{340} Exh. CalCCA-1 at 3-3:15-20.
\textsuperscript{341} Obtained by adding the values for the “PPA-Other” and “UOG-Other” categories in the CalCCA Workpaper “Portfolio Reporting Template Final 040118.xlsx”
\textsuperscript{342} Id.
7. **The SPA Can Reasonably Be Implemented by January 1, 2020**

The Joint Utilities acknowledge that CalCCA’s SPA proposal has merit,\(^3\) and should be considered subject to sufficient development of the implementation details. CalCCA prudently recognized that the precise design of the proposed auction requires more evaluation and analysis than is possible within this phase of the proceeding, and therefore proposed a broad structural and conceptual framework for an auction process that can be further developed by the Commission in a subsequent phase of the proceeding.\(^4\) The timeline contemplated by CalCCA would have workshops on design of the SPA held from late-2018 through mid-2019, followed by Commission review and approval of the SPA implementation details and an initial quarterly auction conducted by January 2020.

CalCCA’s proposed approach provides ample time and opportunity for the Commission, guided by its own requirements and preferences and informed through the engagement of affected stakeholders, to develop a workable auction design that can be implemented in a reasonable manner.

C. **CalCCA’s Proposed Comprehensive Solution Aligns with the Guiding Principles for this Rulemaking.**

The Scoping Memo clearly identified the overall goal of this proceeding and key principles to guide its resolution. CalCCA’s proposed comprehensive solution, incorporating the Corrected Methodology and the Staggered Portfolio Auction, closely align with these goals.

*Avoids cost shifts.* CalCCA’s proposal achieves the overall goal of this proceeding, and indeed the long-standing goal of the Commission in managing departing load impacts, of avoiding cost shifts. CalCCA concludes in Section IV that the Current Methodology shifts costs

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\(^3\) Exh. IOU-3 at 1-3:1-5, 4-3:27-28.  
\(^4\) Exh. CalCCA-1 at 4-2:6-10
from bundled to departing load customers by undervaluing the long-term utility portfolios and including costs that were not intended by the Legislature to be imposed on CCA customers. In the near term, CalCCA achieves this objective by correcting the Current Methodology. By correcting the value measure for capacity, adding values to reflect GHG-free and ancillary service values and correcting the Green Adder, CalCCA’s proposal produces a reasonable portfolio valuation methodology. By removing Legacy UOG costs from PCIA-eligible costs, CalCCA’s proposal aligns the PCIA calculation with the statutory directives regarding cost shifts. Over the next two years, CalCCA’s proposal evolves to address cost shifting by enabling a more transparent and reliable allocation and valuation of portfolio resources through the Staggered Portfolio Auction.

**Transparent, verifiable, confidential and predictable (Principles 1.a-b.).** Both the Corrected Methodology and the SPA provide transparent, verifiable, confidential and predictable means of calculating uneconomic cost responsibility. The Corrected Methodology achieves this objective by relying primarily on values calculated by the Commission for valuation, rather than actual transaction data. The SPA provides a transparent and verifiable result through an auction with publicly available price discovery; while the prices resulting from the SPA may vary more than administratively determined prices over time, the methodology produces a reliable result, predictable in the light of market conditions. Both approaches are made more predictable through the use of utility data, as framed in this proceeding, to enable long-term forecasting in the ERRA under the Modified Nondisclosure Agreement.

**Flexible and accurate over time (Principle 1.c)** The ability of any solution to address market conditions as competition increases is critical. CalCCA’s proposal addresses this issue by transitioning over a two year period to a voluntary, market-based mechanism that allows all
LSEs, including the Joint Utilities, to modify their portfolios as they change and to reflect the impact of those changes in departing load charges.

*Prevents unreasonable obstacles for non-utility LSE customers (Principle 1.d.)* Unlike the Joint Utilities’ proposed GAM/PMM, CalCCA’s proposal does not erect new obstacles for customers of non-utility LSEs. These LSEs retain autonomy in developing portfolios to serve their customers that are consistent with their customers’ needs. The proposal also prevents creating artificial burdens on non-utility customers as a result of failing to adequately value the utility’s bundled portfolio.

*Consistent with California energy policy goals and mandates (Principle 1.e.)* Nothing in CalCCA’s proposal reduces the obligations of any LSE to meet state energy policy goals. Moreover, CalCCA’s proposal increases the capability of all LSEs to meet RPS goals as required by the Legislature in the way that best suits their customers’ needs. A proposal that continues to shift costs to non-utility customers and prevents procurement autonomy, like the GAM/PMM, ties the hands of non-utility LSEs in making choices that will advance state interests.

*Preserves procurement autonomy (Principle 1.f.)* CalCCA’s proposal allows non-utility LSEs to retain procurement autonomy by continuing to allocate uneconomic costs, rather than products or attributes. The Joint Utilities’ forced product allocation under the GAM/PMM renders its proposal unable to fulfill this objective.

*Provides payment flexibility (Principle 1.g.)* CalCCA’s proposal allows non-utility LSEs and their customers the ability to pay for their uneconomic cost responsibility through a PCIA charge and reduce the PCIA-eligible costs by procuring resources from the SPA. Moreover, CalCCA’s proposal for prepayment enables non-utility LSEs and their customers to extinguish all or a part of their obligation in advance to add predictability to their planning.
Reflects legitimately unavoidable costs (Principle 1.h.) CalCCA’s proposal adheres closely to the statute permitting only “unavoidable” costs to be recovered through the PCIA. It achieves this goal by proposing cost reduction measures, including improved portfolio management practices, securitization of UOG assets and buydown and securitization of PPA prices.

Reflects value of benefits to bundled service customers (Principle 1.i.) CalCCA’s proposal is the only proposal that ensures that the cost responsibility of departing load customers is adjusted to reflect value remaining with bundled customers by ensuring reflection of long-term characteristics and value in portfolio valuation. In contrast, the Joint Utilities’ proposals make no adjustment to cost responsibility to reflect bundled customer value.

Preserves all resource value (Principle 1.j.) CalCCA’s proposal is the only proposal that ensures that all resource value is captured, through the use of portfolio valuation measures that recognize long-term value and the implementation of a SPA that effectively values all resource characteristics. In contrast, the Joint Utilities’ GAM/PMM sacrifices long-term value – particularly long-term RPS value, hedge value and optionality – through short-term allocation or sale of products and attributes.

Respects all existing agreements. (Principle 1.k.) CalCCA’s proposal does not contemplate any forced sale, assignment or termination of any PPA.

VIII. THE COMMISSION SHOULD REJECT THE JOINT UTILITIES’ PROPOSED GAM/PMM. (Common Outline §VI)

A. The GAM Is Unlawful

The Public Utilities Code authorizes recovery of certain costs from CCA departing load customers. Public Utilities Code §366.2(f)(2) authorizes the recovery of “share of the electrical
corporation’s estimated net unavoidable electricity purchase contract costs attributable to the customer.” Likewise, §454.51\textsuperscript{345} permits recovery of the costs of additional procurement under the IRP and the net costs of renewable energy integration resources procured by the utility.\textsuperscript{346}

The law does not, however, give the Commission or the utility an unfettered right to allocate resources to CCA departing load, as the Joint Utilities propose to do under the GAM. To the contrary, §366.2(a)(5) grants CCAs autonomy in procuring resources to serve its customers:

A community choice aggregator shall be solely responsible for all generation procurement activities on behalf of the community choice aggregator’s customers….\textsuperscript{347}

The statute makes exceptions solely for “arrangements expressly authorized by statute.”\textsuperscript{348}

The only statutory right for resource allocation to CCA departing load customers is very narrow. While §366.2(g) contemplates a reduction of cost responsibility if the “customers of the community choice aggregator are allocated a fair and equitable share of those benefits,” it does not authorize such an allocation. In only one instance – resource adequacy\textsuperscript{349} – does a statute contemplate the allocation of resources to a CCA, and then only after the Commission has taken the mandate for CCA procurement independence into account.

Section 380(g) provides for the utility’s recovery of the costs of “meeting or reducing resource adequacy requirements….from those customers on whose behalf the costs are incurred, as determined by the commission, at the time the commitment to incur the cost is made.”

Section 380(h) specifies the considerations the Commission must take into account in

\begin{itemize}
  \item \textsuperscript{345} Id. §454.52(c)(emphasis supplied).
  \item \textsuperscript{346} Id. §454.51(c)(emphasis supplied).
  \item \textsuperscript{347} Id. §366.2(a)(5).
  \item \textsuperscript{348} Id.
  \item \textsuperscript{349} Id. §380(h).
\end{itemize}
implementing subpart (g), including “[e]nsuring that community choice aggregators can
determine the generation resources used to serve their customers.”\(^{350}\) (Notably, this provision
was not yet enacted at the time the Commission adopted the CAM.\(^{351}\) Taking the mandate for
CCA procurement independence into account – and only then – may the Commission “consider a
centralized resource adequacy mechanism among other options….\(^{352}\)

The GAM violates the statute’s express terms in allocating RECs to CCAs on behalf of
their customers and fails adequately to consider the impact of further RA allocation on the
procurement autonomy granted by statute to CCAs. As CalCCA witness Hoekstra explained,
“[t]he 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.”\(^{353}\)

Allocation of RECs, rather than the “estimated net avoidable purchase contract costs,”
would impair a CCA’s ability to be “solely responsible” for RPS procurement on behalf of its
customers. CalCCA witness Hoekstra explained that 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” under the GAM, as depicted below.\(^{354}\)

\(^{350}\) Id. §380(h)(5).
\(^{351}\) See AB 380, supra.
\(^{352}\) Id. §380(i).
\(^{353}\) Exh. CalCCA-3 at 4-8:1-2/
\(^{354}\) Exh. CalCCA-3 at 4-4 (emphasis supplied) and Figure 4-2 at 4-5.
Similarly, Mr. Hoekstra concluded that “[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” under the GAM, as depicted below. 355

Figure 4-1

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355 Id. at 4-3 (emphasis supplied) and Figure 4-1 at 4-2.
Making matters worse, the RECs would be untradeable, as discussed in Section VIII.C once allocated to a CCA. Consequently, a CCA that is already fully or even partly RPS-resourced would be forced to sell off other resources in its portfolio to retain a supply-demand balance.  

While the Legislature provided a greater degree of flexibility in the context of Resource Adequacy, the statute does not support GAM RA allocation as proposed. The GAM’s allocation of RA to CCA customers is unnecessary and would have a material impact on a CCA’s sole procurement authority. Mr. Hoekstra examined the impacts of the GAM’s RA allocation in both the SCE and PG&E service territories. For the SCE service territory, he concluded:

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.

He observed that “[a] CCA who is already 60% resourced could suddenly have excess or stranded capacity in its portfolio.”  While to a lesser degree, a CCA in PG&E’s service territory would still be saddled with 29% of its RA requirements under the GAM.  Moreover, there is no evidence that the RA allocations provided by the GAM would be tradable once in a CCA’s portfolio.

The GAM departs unambiguously from the Legislature’s intent to provide CCAs sole autonomy in procuring resources to serve their customers. Moreover, there are clear options available to the Commission that would maintain that autonomy, protect against utility misuse if

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356  See Exh. CalCCA-3 at 4-7:1-2 (“(A CCA who is already 60% resourced could suddenly have excess or stranded capacity in its portfolio.”).
357  Exh. CalCCA-3 at 4-6:2-5.
358  Id. at 4-7:1-2.
359  Id. at 4-5:1-5.
its market dominance, and the utility to continue to allocate stranded costs to CCA departing load customers. Under these circumstances, the Commission must reject the GAM/PMM.

**B. The GAM/PMM Unreasonably Sustains Utility Market Dominance as Bundled Load Declines**

The Joint Utilities have dominated the procurement arena since the beginning of utility history. The Legislature found in enacting SB 790, however, that “[t]he exercise of market power by electrical corporations is a deterrent to the consideration, development, and implementation of community choice aggregation programs.” 360 It further concluded: “California has a substantial governmental interest in ensuring that conduct by electrical corporations does not threaten the consideration, development, and implementation of community choice aggregation programs.” 361

Today, PG&E serves roughly 60% of the load in its service territory, and 35% of the SCE service territory is in the midst of CCA formation. 362 The Joint Utilities’ control of the majority of resources in the service territory, as necessary to meet their anticipated load requirements, seems rational. Commission Staff and other parties agree, however, that the Joint Utilities will not be providing generation services to the majority of their native load by the mid-2020s. 363 As their load continues to migrate to other alternatives, the utilities must reduce the size of their portfolios.

CalCCA’s proposed SPA contemplates this outcome and proposes to reduce the scope of utility resource control. The GAM/PMM, however, does not adjust the supply and demand balance in the market; it simply permits the utility to retain dominance and resource control

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360 Senate Bill 790 (2011), Section 2(f).
361 Id. Section 2(g).
362 Exh. IOU-1 at 1-1:17-23.
363 Id.
while doling out limited, short-term allocations and CAISO settlements\(^{364}\) to CCAs each month or year. The GAM/PMM consequently risks continued “double procurement” and continued, unreasonable utility dominance in the wholesale market to the disadvantage of competitors.

The Joint Utilities echo the concern raised by the Commission’s staff that up to 85% of load could migrate away from the utilities’ portfolios by the mid-2020s.\(^{365}\) Joint Utilities’ witness Wan confirmed his belief that, for PG&E, 85% departure is a plausible scenario and, theoretically, even 100% departure is possible.\(^{366}\) Any departure more than 10% or 20% would, in his view, result in “excess supply.”\(^{367}\) Even today – without 85% departure – PG&E is “long” in RA, energy and RPS supply,\(^{368}\) and Mr. Wan expects that position to increase.\(^{369}\) Yet any plans for reducing the size of the portfolio, through divestiture of UOG or sale of RPS contracts, are at best unclear.\(^{370}\)

Conditions under which the utility holds, for example, 85% of the resources necessary to supply its service territory but serves only 15% of the load would unreasonably sustain utility dominance to the disadvantage of CCA customers and the stability of the California electricity market.\(^{371}\) As witness Marrinan explained:

> 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

\(^{364}\) See, e.g., Exh. IOU-1 at 1:18-28.

\(^{365}\) Exh. IOU-1 at 1-1:22-25.

\(^{366}\) 1 Tr. 36:2-13 (Wan).

\(^{367}\) 1 Tr. 36:25 to 37:21 (Wan).

\(^{368}\) Id. at 38:7-24 (Wan).

\(^{369}\) Id. at 38:26 to 39:1 (Wan).

\(^{370}\) See generally 1 Tr. 39-40:28 (Wan).

\(^{371}\) See generally Exh. CalCCA-3, Chapter 4, §I.G. at 4-15.
would provide them with a highly unfair advantage to compete to supply generation to CCA or other departing load customers.\footnote{372}{Exh. CalCCA-3 at 4-15:9-15.}

She further explained that while utilities today are limited in their ability to impact spot prices, “because they have significant load that offsets their generation positions…. their net long generation position could create a market power issue.”\footnote{373}{Exh. CalCCA-3 at 4-15:23 to 4-16:4.} Finally, she observed:

> Given the potential harm an IOU could cause a CCA, the standard of care and oversight in 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.\footnote{374}{Id. at 4-16:4-10.}

The GAM/PMM would place the Joint Utilities in a continuing position of dominance, controlling a material portion of the resources necessary to serve other LSEs and holding a substantial information advantage. For these reasons, the Commission should reject the GAM/PMM.

\section{The GAM/PMM Devalues Portfolio Resources}

\subsection{GAM Allocations of RECs Reduce or Eliminate the “Bundled” and “Long-Term” Value of the Underlying RPS Resources}

Long-term assets or contracts held in the portfolio are substantially different products than short-term rights to these resources sold in the market. Selective excess supply attributes sold on a short-term basis cannot convey the full value of the underlying resources and thus an incremental value is retained within the bundled portfolio – a value that by statute must be credited to departing load customers.\footnote{375}{Cal. Pub. Util. Code § 366.2(g).} Alternatively, however, selective excess attributes sold...
on a short-term basis may devalue the resource for all purposes, losing value for bundled customers without conveying the value to departing load customers.

The GAM’s proposal for an allocation of RECs to departing load customers risks devaluing the underlying RPS resources. Contracts underlying the REC allocation have several uniquely valuable attributes, including their “bundled” and long-term characteristics. The GAM, however, cannot convey all of the value, but will convey the cost, of these attributes to departing load customers.

Bundled RECs have a value that is greater than unbundled RECs, due to the statutory requirement of §399.16(c)(2) that limits the use of unbundled RECs for compliance to 10% following December 31, 2016. As the Joint Utilities acknowledge: “the value of RECs varies significantly amongst the various portfolio content categories (i.e., PCC 1, PCC 2, PCC3).”376 By definition, however, transferring bundled RECs from the portfolio without the energy “unbundles” the RECs, potentially losing their PCC 1 value. To avoid this result, the Joint Utilities request a finding by the Commission that the RECs transferred under the GAM, “by virtue of that allocation, become ‘unbundled RECs’ as that term is used in Section 399.16(b)(3).”377

The Joint Utilities’ proposal runs directly contrary to the Commission’s conclusions in D.11-12-052. In delineating the categories of RPS complaint resources, the Commission explained:

Regardless of whether the original generation and RECs would have counted in the "bundled" category under D.10-03-021, or in another portfolio content category under new § 399.16 if the RECs had been retired for RPS compliance without being transferred, once they are unbundled and transferred, the RECs are

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376  Exh. IOU-1 at 4-40:31 to 4-41:1.
377  Exh. IOU-1 at 4-44:12-15.
by definition unbundled RECs, subject to the rules of that portfolio content category.\textsuperscript{378}

The Commission further observed the “overarching tenet that once RECs have been unbundled and sold separately from the RPS-eligible electricity with which they were originally associated, the electricity may not be used for RPS compliance.”\textsuperscript{379} While the Joint Utilities attempt to “nuance” this point, suggesting that these RECs are not being “sold,”\textsuperscript{380} the fact remains that the customer “is paying for the REC.”\textsuperscript{381} If, instead, the Joint Utilities were to sell RPS contracts, the REC would retain its bundled status.\textsuperscript{382}

Even assuming the Commission could “nuance” statutory compliance by deeming allocated RECs to be “bundled” RECs, the RECs would be devalued. The Joint Utilities contend:

It should be noted that LSEs are not required to use the allocation of attributes they receive on behalf of their customers, and can instead elect to sell them (or not use them, although it would be uneconomic to do so).\textsuperscript{383}

On the stand, however, Mr. Cushnie acknowledged that he had not considered the potential loss of the bundled attribute if the LSE resold the REC to a third party. After consideration, he concluded: “If they are selling bundled REC, it remains an unbundled REC.”\textsuperscript{384} In short, while the RECs may be tradable, they lose value if that ability is exercised.

A similar problem arises with the “long term” attribute associated with RPS resources. Beginning in 2021, §388.13(b) requires that 65% or more of RPS compliance must come from contracts of a term of longer than 10 years or resource ownership, conveying greater value on

\begin{flushright}
\textsuperscript{378} D.11-12-052 at 55.  \\
\textsuperscript{379} \textit{Id.} at 56.  \\
\textsuperscript{380} 2 Tr. 293:1-5, 404:23-405:4 (Cushnie).  \\
\textsuperscript{381} \textit{Id.} at 367:28 – 368:6-10 (Cushnie).  \\
\textsuperscript{382} 2 Tr. 295:26 – 296:1 (Cushnie).  \\
\textsuperscript{383} Exh. IOU-1 at 4-41:4-7.  \\
\textsuperscript{384} \textit{Id.} at 292:6-8 (Cushnie).
\end{flushright}
these longer term arrangements. Under the GAM, however, the utility would have no contract commitment to transfer RECs to an LSE for any period, and would only transfer them after they are generated, on a quarterly basis. The LSEs receiving the RECs would not be party to the underlying contracts. Yet the Joint Utilities claim that allocation would be a “significant reduction in the required new long-term contracting by other load-serving entities.” In reality, the CCAs could not rely on the short-term allocations to meet their statutory requirement for 10-year resources even if it were not unlawful to count the allocations toward this requirement. The amount of time it would take a CCA to construct or procure 10-year resources in the event of a shortfall in anticipated allocation would significantly outstrip the notice period provided by the utility regarding the quantity of RECs to be allocated. The result of a CCA properly managing this risk would be a continued “double procurement” of resources. Again, the Joint Utilities attempt to distinguish the GAM on grounds that “we’re not selling it to a load-serving entity…."

The Joint Utilities again ignore the language of the statute. Section 399.13(b) provides:

Beginning January 1, 2021, at least 65 percent of the procurement a retail seller counts toward the renewables portfolio standard requirement of each compliance period shall be from its contracts of 10 years or more in duration or in its ownership or ownership agreements for eligible renewable energy resources.

The short-term GAM allocation does not somehow transform the unbundled REC, or even a bundled REC, into the receiving LSE’s long-term contract or ownership. Not even interpretation by the Commission can overcome the plain language of the statute. Moreover, as with the

385 Exh. IOU-1 at 4-23:14-21.
386 2 Tr. 299:15-18 (Cushnie).
387 Id. at 300:3-9 (Cushnie).
388 Id. at 301:16-19 (Cushnie).
“bundled” characteristic, the Joint Utilities acknowledge that the receiving LSE cannot “sell that long-term attribute to other load-serving entities.”

2. The GAM/PMM Fails to Preserve and Convey All Value of the Portfolio Resources

Long-term contracts and assets carry value beyond the value of short-term rights to products unbundled from those contracts or assets, including hedge value and optionality. The GAM allocation does not convey those values to departing load customers, leaving the value behind in the portfolio to support bundled portfolio management.

CalCCA witnesses Marrinan and Hoekstra identified the loss of value for departing load customers in several respects:

- “[T]he 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, including GHG-free energy value, hedge value and other products.”

- “[T]he 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…” including the “flexible storage, dispatch, ramping and arbitrage capabilities inherent in Large Hydro (including pumped storage)” and the “flexibility in the administration of RPS resources (e.g., curtailment provisions, term extensions, price resets, etc.).”

- The PMM “merely transfers costs to CCAs without any transfer of control over the resources themselves [which is] more fully realized and maximized when conveyed between counterparties via forward contracts and forward contract prices….”

- The PMM fails to realize the “value of GHG-free energy available from nuclear resources or the intrinsic forward gas conversion tolling value of gas resources….”

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390  2 Tr. 301:16-19 (Cushnie).
391  Exh. CalCCA-3 at 4-9:1-17.
392  Id. at 4-9:18 to 4-10:3.
393  Id. at 4-10:20 to 4-11:8.
394  Id. at 4-11:9-14.
The PMM fails to realize “extrinsic” resource 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.”

Moreover, despite the utilities’ claims to the contrary, the GAM/PMM does not produce the value of predictability for departing load customers. As Ms. Marrinan explains: “The quantities will vary from quarter to quarter for RECs and month to month for RA...[t]he 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.” This would leave CCAs unable to predict what will be available to them.

The result would be a significantly loss of value in the hands of departing load, leading to a “portfolio that is un-hedgeable, unmanageable and whose costs are highly volatile.” Hedge value in GAM is insufficiently transparent for practical planning purposes. To the extent that the GAM rate reflects the hedge value inherent to the underlying contract for the resource, the aggregated nature and ever-changing composition of the IOU portfolios makes it nearly impossible to use those hedges to practically manage a CCA’s positions. Ms. Marrinan anticipates that “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.”

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395  Id. at 4-11:15-21.
396  Exh. CalCCA-1 at 4-13:4-9.
397  Id. at 4-13:16-17.
398  Id. 4-14:18-20.
The GAM/PMM threaten significant loss of value as long-term utility resources are conveyed quarterly or annually, on a short-term basis. The proposal thus fails to meet the Guiding Principles advanced in the Scoping Memo.

**D. The GAM/PMM Is Not a Long-Term Solution Yet is Too Incomplete and Complex to Serve as an Effective Interim Solution**

The Joint Utilities have marketed the GAM/PMM solution as a simple “turnkey” solution reforming the uneconomic cost allocation methodology. The GAM/PMM presents anything but a simple solution. The only “turnkey” solution in the short-run is modification of the Current Methodology to reduce the risk of cost shifts between bundled and departing load customers.

The Commission lacks the requisite legal authority to implement the GAM, and the GAM/PMM will result in a loss of value of the underlying portfolio resources. In addition, the proposal suffers from numerous flaws that will prevent simple or timely implementation.

First, the Joint IOUs acknowledge that changes are required to the Power Content Label rules to ensure the proper accounting for resources subject to GAM/PMM.\(^{399}\) They further acknowledge that these issues are not within the scope of this Commission’s jurisdiction but instead lie within the Energy Commission’s discretion.\(^{400}\) Resolution of these complex, multi-jurisdictional issues is unlikely to be completed for a “turnkey” implementation of the GAM/PMM on January 1, 2019.

Second, the question of how banked RECs should be addressed in the GAM/PMM proposal has not been adequately explored. The Joint Utilities propose allocating banked RECs from the IOU portfolios to departing load ratably over the term of the longest contract in the

\(^{399}\) Exh. IOU-1 at 4-45.

\(^{400}\) 2 Tr. 302:17-21.
vintaged portfolio. Setting aside the questionable equity of such a proposal (why do bundled customers have full access to their bank immediately, but departing load customers are slowly given their bank over 20-30 years?), the regulatory and legal basis for such a change is unclear and would need to be reviewed considering all the facts prior to implementation.

Third, multiple recalculation of GAM RA amounts make planning to meet RA requirements a moving target. Under the Joint IOU proposal, GAM RA allocations would be initially determined in August based on year-ahead load share. The allocation would subsequently be updated during the month-ahead and mid-year periods, introducing significant uncertainty to the actual GAM RA allocations that the departing load entity would receive. As noted in Section VIII, this uncertainty complicates departing load resource planning and creates a barrier to hedging by CCAs.

Fourth, the Joint Utilities propose complex rules for replacement and substitution of RA on behalf of the LSEs receiving allocations. The Joint IOUs propose a complex, tiered process for RA replacement and substitution for the GAM RA portfolio that has implications for the CAM and PMM portfolios. For example if GAM RA requires substitution, the Joint Utilities propose leaving it to their discretion to choose from a menu of options including drawing from the PMM portfolio, the CAM portfolio, or even procuring new resources to meet the substitution requirement. Keeping track of numerous transactions and ensuring they were all done reasonably will be a challenging task for the utilities, Commission and stakeholders. Oversight to ensure fairness would be critical to such a process and further stakeholder input would be required to fully vet the overlapping issues introduced by this aspect of the Joint IOU proposal.

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401 Exh. IOU-1 at 4-22, n. 5.
402 Id. at 4-25:19 to 4-26:22.
403 Exh. IOU-1 at 4-28:1 to 4-29:17.
Fifth, the Joint IOUs propose a stakeholder process including the IOUs, CCAs, ESPs and CAISO to determine how to avoid stranding import RA under the GAM proposal. Such a process would be necessary to implement the Joint IOU proposal and would need to be completed prior to implementation GAM/PMM to ensure resource value is not lost. Again, completion of this process is unlikely to occur in sufficient time for a 2019 implementation.

Sixth, while the Joint Utilities’ criticize the longer term auction strategy proposed by CalCCA as “incomplete,” the PMM auction – which the utilities propose as a near-term solution – raises many issues that would need to be addressed prior to implementation. For example:

- The combination of departing load and bundled load transactions, with the utilities on both sides of the transaction in the same RFO, raises significant oversight issues that need to be carefully considered. Although the Joint IOU testimony reference rules used in CAM Energy Auctions, the PMM process is more complex and any such rules would need to be revisited.

- The PMM auctions could be subject to gaming. The Joint Utilities offer no discussion of what bid selection criteria would be used to award RA contracts. It is unclear how they propose to avoid a situation where RA in the Q1 long-term RA sales RFO is sold at artificially low prices instead of holding back such a quantity for sale later in the year. Departing load customers would have no influence over such decisions, but would bear the financial consequences of the utilities’ decisions. Moreover, if the Joint IOUs award RA contracts at artificially low prices, this could lead to speculation and market manipulation that could impair the ability of all parties to meet their RA obligations.

The GAM/PMM thus not only fails on legal and policy grounds but fails to offer a solution that can be implemented in the near term. It also introduces a possible volatility and opportunity for market manipulation which the Commission has indicated is a high concern in the current dynamic marketplace. The only near-term solution is to modify the Current Methodology to

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404 Id. at 4-29:18-33.
405 Exh. IOU-3 at 4-2:27-28.
mitigate the risk of cost shifts and look toward a more comprehensive reform over the next two years, as proposed by CalCCA.

IX. IMPROVEMENTS IN PORTFOLIO MANAGEMENT PRACTICES SHOULD BE ADOPTED TO REDUCE AND PREVENT FURTHER ACCUMULATION OF UNECONOMIC PORTFOLIO COSTS (Common Outline §VII)

A. The Commission Should Direct the Joint Utilities to Modify Their Forecasting Practices to Better Account for Departing Load

The Commission and the Joint Utilities have long been aware of the need to consider and forecast departing load in developing and implementing procurement. The issue was central to the procurement by the California Department of Water Resources (CDWR) following the energy crisis. In D.03-04-030, the Commission established an exemption from the CDWR Power Charge based on CDWR’s forecast of departing load. It stated:

> It is clear that DWR, when negotiating long-term power contracts, assumed that a certain amount of customer generation departing load would occur every year and therefore did not procure long-term power for that portion of the load. In fact, such an assumption is based on common sense, since utilities have always faced departing load in various forms, including that caused by an economic downturn, improvements in energy efficiency and building codes, as well as installation of self-generation systems.406

The Commission drew two important conclusions, relevant to this proceeding: forecasting departing load is “common sense,” and departing load accounted for in a forecast underlying a procurement plan should be exempt from cost responsibility for resources procured in implementing that plan.

Despite this clear awareness (or perhaps in response to this awareness), the Joint Utilities undertook the most extreme short-term focused and narrow approach to forecasting departing load from the outset of CCA formation. As evidenced in the cross examination of the Joint Utilities witnesses, the Joint Utilities refused to forecast CCA departing load in developing or

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406 D.03-04-030 at 54.
implementing procurement plans absent near certainty that a particular load would depart.

Mr. Cushnie explained:

In the case of Southern California Edison, what we're looking for is for the newly-forming CCA to give us sufficient confidence as to their formation plans so that we can then plan to balance the portfolio around their formation intentions. To date, only one of our CCAs has provided a binding notice of intent, which is the Commission's regulatory process that tells us that we can now officially not plan to serve that load.\footnote{407}

As a result of this standard, SCE failed to forecast any CCA departing load until its 2016 ERRA filing, after Lancaster Choice Energy customers departed in mid-2015. \footnote{408} Mr. Lawlor stated that PG&E forecasts departing load in a “similar fashion.”\footnote{409} He further observed: “I truly think our forecasting is getting better, but you know, nothing better than a binding notice of intent.”\footnote{410}

Another major forecast shortcoming was that the Joint Utilities focused on the very short-term and on the precise date that a particular CCA load would depart over the next year in the annual ERRA Forecast process and did not consider the long-term plausible range of potential departing load over the 20-30 year horizon covered by the long-term resource commitments they were making. Until just the past couple of years, the Joint Utilities generally assumed that future departing load would continue on a flat-line basis for an indefinite number of years into the future at exactly the same level as the most recent year-ahead ERRA forecast, without regard for potential future departing load several years into the future. Consequently, the Joint Utilities’ narrowly-defined departing load forecasting approach missed the forest for the trees, and completely missed the potential for the dramatic increases in departure that we are being experienced

\footnote{407} 4 Tr. 809:20-810:3 (Cushnie).
\footnote{408} 4 Tr. 825:1-3(Cushnie).
\footnote{409} 4 Tr. 813:9-10 (Lawlor).
\footnote{410} 4 Tr. 814:13-16 (Lawlor).
now. Indeed, the record in this case is replete with references to the potential departure of up to 85% of the Joint Utilities’ bundle load within the next several years – but is devoid of even a hint that the utilities have any structured forecast or plan to deal with the consequences of that outcome.

Mr. Lawlor further confirmed PG&E’s historical forecasting practices. He confirmed that PG&E was aware of the intent of Marin Energy Authority (MEA, now Marin Clean Energy or MCE) to launch a CCA in 2010, as evidenced by implementation plans submitted to and certified by the Commission.\textsuperscript{411} Despite this knowledge, he explained, PG&E “concluded we needed to use more of a bright line methodology, and that looked at binding notice of intent or basically when they go live….”\textsuperscript{412} Consequently, PG&E did not forecast MEA’s departure before its launch.\textsuperscript{413}

PG&E’s failure to actively forecast CCA departing load had serious consequences for MEA and its customers. PG&E continued to procure resources now attributed to MEA’s customers’ behalf for another seven months after the load had already departed.\textsuperscript{414} In fact, PG&E executed contracts for an additional 1.7 GW of new capacity now attributed to MEA’s 2010 departing load despite full knowledge of MEA’s intent to launch, with contracts totaling more than 600 MW executed after the load had already departed.\textsuperscript{415}

Adding insult to injury, the Joint Utilities’ witnesses acknowledged that advance knowledge of MEA’s departure would not have altered their procurement plans.

\textsuperscript{411} 4 Tr. 817:13 – 820:16; 821:26-822:3 (Lawlor).
\textsuperscript{412} 5 Tr. 857:13-17 (Lawlor).
\textsuperscript{413} 5 Tr. 857:18-21 (Lawlor).
\textsuperscript{414} See Exh. CalCCA-123, PG&E 2010 Contract Execution Dates From Attachment 10 ALJ Requested Data Matrix; see also 4 Tr. 820:17-823:20 (Lawlor).
\textsuperscript{415} See Exh. CalCCA-123, Maximum Contract Capacity.
Mr. Lawlor stated that “Marin as a percentage of PG&E’s total load was between 0.1 percent and 0.2 percent” in 2010.416 In Mr. Lawlor’s opinion, a reasonable portfolio manager would not have made any procurement decisions based on the potential departure of this small level of load.417 This perspective was confirmed by Mr. Wan on behalf of the Joint Utilities. He made clear that not all load departures would leave the utility with “excess supply.”418 In fact, to have any impact, Mr. Wan concluded that the departure would need to be in the neighborhood of 10-20 percent.419 Despite far more load departure than 10-20 percent, despite clear expectation from the Commission that the IOUs would adjust their procurement practices to address departing load, and despite clear obligations to minimize costs under Standard of Conduct No. 4, PG&E has done nothing to adjust its portfolio following the departure of CCA load until only very recently.420

Finally, nothing in the Joint Utilities’ strategies or Commission decisions provides for any exemption for departing load that was forecasted, contrary to the approach adopted in D.03-04-030. Thus, even if MEA’s load departure had been forecast in advance of procurement, there would be no basis for exemption under current rules.

While Marin Clean Energy is only one example, PG&E’s response to MCE’s formation demonstrates that PG&E’s strategy was to ignore CCA departing load in procurement and portfolio management, and to saddle these customers with additional costs. Marin Clean Energy’s customers departing in 2010 now unfairly bear the

416 5 Tr. 853:25-854:1 (Lawlor).
417 5 Tr. 855:5-9 (Lawlor).
418 1 Tr. 36:25-37:5 (Wan).
419 1 Tr. 37:17-21 (Wan).
420 4 Tr. 822:24-28 (Lawlor).
uneconomic costs of contracts executed when PG&E had clear knowledge of their departures. And they bear this cost responsibility despite the fact that the departure did not create excess supply nor would have changed PG&E’s procurement strategy in any way. These costs cannot be reasonably “attributable” to MCE in any sense of the word. Moreover, set in the context of the Commission’s clear analysis in D.03-04-030, it is difficult to see PG&E’s conduct as anything but unreasonable. Either PG&E continues to hold all of these resources procured after MCE’s departure (and any other similarly situated CCA) solely for the future benefit of its bundled ratepayers, or PG&E failed to act in accordance with state law and Commission decisions directed it to respond to these load departures for portfolio planning and management.

Only recently, in 2016, have PG&E and SCE begun to take a more reasonable approach for forecasting departing load. SCE has marginally increased flexibility in the timeline for forecasting departing load. As Mr. Hoekstra explained on behalf of CalCCA: “Before 2016, a specific CCA was excluded from SCE’s bundled service forecast only upon the occurrence of: (1) start of CCA service or (2) filing of a binding notice of intent….” Today, SCE also relies on a third criterion: participation in the CPUC’s RA proceeding.” SCE uses this information in stochastic modeling of

421 PG&E’s activities are also suspect given their ongoing campaign to thwart CCA formation which lead to SB 790 and the Code of Conduct. Only a hidebound utility can argue that load departure was not certain enough to be modeled within its procurement strategies or was too small to impact procurement, yet that same expended enormous corporate resources to fight MCE’s formation with such a level of misinformation that the Legislature and then the Commission had to constrain it’s behavior. Yet that is exactly what Witness Wan would have the Commission believe.

422 Exh. CalCCA-1 at 3-12:20-21.

423 Id. at 3-12:17-19.
expected CCA load departure.  Mr. Hoekstra noted that “PG&E likewise has more recently adopted a stochastic modeling approach to forecasting departing load.”

While these changes are “a step in the right direction,” they are too little, too late for many departed customers and highlight the long-standing utility practice of ignoring the potential for CCA departing load – to the detriment of all customers responsible for uneconomic costs. The Commission should take several actions in response to these issues. First, the Commission should require the Joint Utilities to more aggressively anticipate departing load, rather than waiting for a binding notice of intent to account for the risk in its bundled load forecast. A reasonable portfolio manager should use “common sense” in forecasting departing load, as articulated in D.03-04-030. The utilities already used probabilistic methods for forecasting all other loads—they long ago abandoned straight-line trend forecasting methods, and certain customer groups, particularly large industrial and agricultural, exhibit volatile and uncertain load growth.

Second, the Commission should provide for an exemption from contracts executed in a certain year up to the amount of departing load forecast for that year. If the utility excludes an amount of departing load in establishing its procurement plan, any procurement under the plan cannot reasonably be “attributable to” departing load up to the forecast departing load amount, as concluded by D.03-04-030. Third, the Commission should prohibit the Joint Utilities from imposing uneconomic costs for contracts executed after a customer departs, even if executed in the year of departure. It defies logic to conclude that such contracts are “attributable to” load that has already

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424 Id. at 3-13:3-5.
425 Id. at 3-13:16-17.
departed. Finally, the Commission should require the Joint Utilities to prepare and file scenario-based assessments of the potential long-term range of future load departure and ensure that the resource plans and procurement commitments provide adequate flexibility to adapt to the resulting range of supply obligations many years into the future.

Mr. Hoekstra, on behalf of CalCCA, observed the importance of reasonable forecast “in avoiding unnecessary procurement and inappropriate attribution of the costs resulting from that procurement.” Forecasting, he continued “will mitigate the risk of excess long-term procurement...which in turn will minimize stranded assets and above-market costs.” He concluded that “[f]ailure to sufficiently recognize the departing load risk directionally results in over-procurement.” Taking action in improving the Joint Utilities approach to forecasting and the use of departing load forecasts is critical to fair stranded cost allocation and avoiding further accumulation of stranded costs.

**B. The Commission Should Direct the Joint Utilities to Improve Portfolio Management Practices**

The Joint Utilities “have a responsibility on behalf of all customers to minimize costs.”

Notably, Standard of Conduct 4 provides:

> In administering contracts, the utilities have the responsibility to dispose of economic long power and to purchase economic short power in a manner that minimizes ratepayer costs.

The Joint Utilities agree that the Commission can disallow costs under a contract that has been approved by the Commission in cases where the utility has mismanaged that contract, typically

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427 *Id.*
428 *Id.*
429 2 Tr. 322:14-14 (Cushnie) (emphasis supplied).
430 *Id.* at 2 (citing PG&E’s Approved Bundled Procurement Plan at page 26).
in the ERRA. While CalCCA agrees with this conclusion, the ability to challenge utility contract or asset management in the ERRA proceeding remains subject to dispute, as discussed further below.

The Joint Utilities contend that they have made material efforts to manage their portfolios in the face of declining load. CalCCA questions these efforts, observing that the utilities admit that by practice they make no adjustments to their procurement plans as a direct response to departing load, but manage on the basis of the total generation portfolio. (How the utilities account for changes in load is unclear from the record.) Moreover, the utilities made no material efforts to sell their long positions until early 2018 – conveniently right before testimony was filed in this proceeding. Finally, certain of the actions taken by the utility do not benefit all customers, but favor only bundled customers. CalCCA proposes measures that may improve these utility practices so that portfolio management is actively conducted on behalf of all customers.

1. **Require the Joint Utilities to Actively Manage Their Portfolios in Response to Departing Load**

   The Joint Utilities have made clear that they do not modify their procurement plans in direct response to departing load, but generally manage procurement “in a bundled way.” For example, even if PG&E had binding notice of Marin’s departure on January 1, 2010, the utility would not have altered its procurement of RPS contracts. As Mr. Lawlor explained that “PG&E I think was at about, in 2010, 16 percent RPS. We would have continued to procure

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431 2 Tr. 368:17-369:12 (Cushnie).
432 Exh. IOU-1 at 3-2 through 3-4.
433 4 Tr. 822:24-28 (Lawlor).
434 4 Tr. 823:14-20 (Lawlor).
Failing to manage the portfolio in response to departing load can have economic consequences for departing load customers and muddles the issue of which costs are reasonably attributable to those customers.

Economic consequences for departing load customers arise in a declining price market. CalCCA witness Hoekstra observed that “[t]he utilities have had opportunities to sell assets, avoiding a continuing stranded cost, as customer departure has occurred.”

Providing an example, he explained:

PG&E had the opportunity to sell a portion of its RPS portfolio to SCE and SDG&E in 2010 (and perhaps municipal utilities who also face an RPS mandate) as Marin Clean Energy (later MCE) exited bundled service. According to the Green Adder included in PG&E’s 2010 ERRA workpapers, a benchmark that is based on transactions for all three IOUs, PG&E could have sold MCE’s share of PG&E’s RPS portfolio for $149/MWh. Similarly, the share for Sonoma Clean Power could have been sold in 2013 for $120/MWh based on the reported ERRA index. Even if PG&E did not sell MCE’s and SCP’s portions immediately, the utility could have sold those portions for more than $92/MWh at any point before 2017. Today, however, those resources are valued by the MPB at only $82/MWh.

He concluded that similar opportunities have been available as other CCAs exited and may be available going forward. If the utility could have sold that customer’s share – whether to a third-party or to the bundled portfolio – but elected not to make the sale, the ensuing accumulation of uneconomic costs is “avoidable” and cannot reasonably be “attributable to” the departing customer.

Two solutions present themselves. First, if the utility fails to sell the customer’s share of the portfolio in a declining price market, the Commission could deem that share as having been “sold to” the bundled load. This approach would be consistent with Mr. Lawlor’s testimony

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435 Id. (emphasis supplied).
437 Id. at 2A-6:2-12.
concerning circumstances surrounding Marin’s departure; with full knowledge of Marin’s departure, PG&E would not have reduced its RPS procurement and executed the 2010 contracts and would still have procured the resources on behalf of bundled load. This approach is also consistent with PG&E’s approach spelled out in its “2016 Draft Renewable Energy Procurement Plan” in which continues to hold RPS-eligible PPAs for “managing the risk of being caught in a ‘seller’s market,’ where PG&E faces potentially high market prices in order to meet near-term compliance deadlines.”

Alternatively, the Commission could set the benchmark for the departing customer’s share at the Green Adder for the customer’s year of departure. Given that these Green Adder represents the average of the market transaction prices for long-term procurement in that year, this is representative of the economic value to all ratepayers at that time. Bundled customers would be buying back the portfolio share from departed customers at the contemporary going price. This avoids any inappropriate ongoing failure-to-mitigate risk that is now arising as the utilities continue to manage the portfolio for both existing bundled customer load and now-departed customer load. The utilities are now retroactively truing up this departure transaction to mitigate the costs of their portfolios rather than managing those portfolios appropriately in the sole context of their bundled load. As Mr. Hoekstra explained “[i]n this way, the utilities will be given the correct incentive to reduce their portfolio holdings in a manner that maximizes the value for all ratepayers.”

438 4 Tr. 823:14-20 (Lawlor).
439 5 Tr. 901: 16-21 (McCann)
441 Exh. CalCCA-1 at 2A-7:2-4.
2. **Prohibit the Joint Utilities’ Practices Aimed to Protect Shareholders and Bundled Ratepayers at Departing Load Customers’ Expense**

The Joint Utilities’ policy witness, Mr. Wan, testified that interests of bundled and departing load customers are 100 percent aligned in portfolio management.\(^{442}\)

\[^{442}\] 1 Tr. 51:6-13.

, however, tells a different story.\(^{443}\)

\[^{443}\] CONFIDENTIAL Exh. CalCCA-102-C.

Exhibit 102-C describes PG&E’s Resource Adequacy Strategy for 2017 through 2018. PG&E’s RA strategy highlights key risks and mitigations.\(^{444}\) The identification of risk reveals a point where interests diverge, requiring recognition in shaping the Joint Utilities’ procurement practices.

The strategy identifies two risks that implicate divergent interests.

\[^{444}\] Id. at 2-4.

\[^{445}\] Id. at 3.

\[^{446}\] Id.

\[^{447}\] Id. at 4.
The memorandum goes further to point out diverging bundled and departing load customer interests.

Finally, the manner in which PG&E’s strategy contemplates selling RA will affect the relative value to bundled and departing load customers.

Id. at 5, n. 6.
As Dr. McCann explained on behalf of CalCCA:

[U]tilities do hold those assets as hedges against future both reliability risk and price risk. So that there is an inherent value in holding those assets in excess of the short-term reserve margin requirements. 452

Making short-term sales, however, does not yield prices that reflect the “full value” of the underlying resource, thus leaving excess value – value paid for by departing load customers – in the utility portfolio as a hedge for the benefit of future bundled requirements. Moreover, due to the deadlines for LSEs to submit their year-ahead and month-ahead RA compliance filings, waiting until the last minute to make short-term RA sales inevitably leads to the realization of little or no value because the value of RA declines precipitously at (or just before) these deadlines occur.

RPS procurement provides another example of the divergent interests of bundled customers and departing load customers. Dr. McCann explained that utilities use hedge values in determining their procurement plan and management of their portfolio. Dr. McCann quoted from PG&E’s 2016 Draft Renewable Energy Procurement Plan at page 19:

PG&E’s fundamental strategy for mitigating RPS cost impacts is to balance the opposing objectives of, one, delaying additional RPS-related costs until deliveries are needed to meet a physical compliance requirement, and two, managing the risk of being caught in a seller's market where PG&E’s potentially high mark basis, potentially high market prices in order to meet near-term compliance deadlines. When these objectives are combined with general need to manage overall RPS portfolio volatility based on demand and generation uncertainty,

450 Id. at 7.
451 Id. at 8.
452 5 Tr. 952:4-12 (McCann).
PG&E believes it is prudent and necessary to maintain an adequate bank, [that's the RPS bank], through the most cost-effective means available.453

While maintaining excess RPS hedges the future risk of bundled customers, the strategy may not be best suited for departing load customers. If, as discussed above, the Utility has the opportunity to sell a departing load customer’s share of the portfolio RPS position in a declining market, but instead maintains the share in the portfolio, the Utility is benefitting bundled customers in hedging future risk at the expense of departing load customers.

This hedge value can be calculated using market data—it is the difference between the discounted future cost of continuing to hold the RPS PPAs and the current “mark to market” value of liquidating the contracts today. This is a market valuation of a clearly-identified and delineated benefit that accrues to bundled customers. Using the data from PG&E’s ALJ Data Template,454 we can calculate the weighted average cost of the PG&E’s RPS-eligible PPAs for 2018 to 2017, calculate the net present value of those PPAs using PG&E’s weighted average cost of capital from its 2017 General Rate Case, and calculate the implied hedge premium by subtracting the current RPS market price benchmark from the 2018 PCIA. Based on those calculations, PG&E’s market-based hedge valuation is

CCA customers are left to pay for this hedge value that accrues solely to bundled customers, generating a subsidy to those customers. Meanwhile, CCA customers must build their own RPS portfolios that include hedging price risk, with no subsidies from bundled customers.

453  5 Tr. 901:3-902:1 (McCann).
454  PG&E-Attachment 10 ALJ Requested Data Matrix MODIFIED CONFIDENTIAL.xlsx, sheet ALJ Template
The divergence of interests of bundled and departing load customers in the context of RPS procurement can also be seen in the context of Marin’s 2010 departure. Mr. Lawlor acknowledged that even if they had received their required indication that Marin customers were planning to depart in 2010, they would still have procured the contracts on behalf of bundled load. Effectively, PG&E was intent on pursuing its strategy for RPS procurement, and bundled customers got lucky enough to be able to offload the costs of the bundled strategy on departing load customers.455

The muddling of bundled and departing load interests, in both RA and RPS procurement policy, makes attribution of cost responsibility to departing load customers challenging, at best. Based on the evidence in this proceeding, the Joint Utilities are likely attributing cost responsibility to departing load customers for costs of resources that were not acquired for them and may have been avoidable at the time they were incurred. Even setting this issue aside, one change is necessary: departing load customers should not be paying for excess resources acquired or maintained to hedge bundled customers’ compliance and price risk.

One solution, for future procurement, was recommended in CalCCA’s opening testimony. In evaluating new resource commitments:

[T]he Commission should make three explicit determinations: (1) the expected effect of the commitment on the PCIA rate for all vintages of departing load; (2) whether the utility’s forecast of departing load was reasonable at the time the resource commitment was made; and (3) to which vintages of departing load the commitment is attributable.456

The Commission should similarly examine the role and impact of departing load in the context of the Joint Utilities’ Bundled Procurement Plans to assess the extent to which

455 Id. (emphasis supplied).
those plans account for departing load and the extent of resources stranded by a customer’s departure. While these measures are not complete solutions, they enable the Commission to make a focused inquiry to bring awareness to the potentially divergent interests of bundled and departing load customers.

Finally, the existence and ease of calculating the hedge premium for holding RPS PPAs to mitigate price risk on behalf of bundled customers should be included in the market valuation of the PCIA-eligible portfolio. This amount is additive to the Green Adder MPB in the PCIA until the SPA is implemented to reveal the full value of the utilities’ portfolios.

3. **Require the Joint Utilities to Optimize Sales from Their Portfolios to Capture the Full Value of the Resources for All Customers**

The record is devoid of evidence demonstrating that the Joint Utilities have taken steps to optimize the value of their portfolios. All signs point to a strategy to procure and hold on to resources sufficient to meet all load in their territories except for the very minimum that is absolutely certain to depart in order to mitigate all potential RA or RPS compliance risk and then offload excess RA capacity in the short-term market or bank RPS credits until needed to serve bundled load at some point in the future. The apparent result is that the Joint Utilities intend to hold on to the resources in their portfolios as long as they can possibly just doing so, and then make limited adjustments in reaction only to the year-to-year changes that are known to occur with near-certainty. As with the Joint Utilities’ misguided focus on short-term departing load forecasts discussed above, this portfolio management strategy wastes value in the portfolio and fails to adequately mitigate excess costs in the portfolio for the benefit of departing load customers. This strategy retains for bundled customers, to the exclusion of benefiting departing load customers, the hedge value and the value of optionality, market information and other long-
term attributes that are actually inherent in the supply portfolios, yielding an artificially depressed “market” value for a different, much more limited product.

Until shortly before testimony was due in this proceeding, the Joint Utilities had not engaged in forward sales of more than one year, failing to realize the full value of the long-term resources embedded in the portfolio. The recent sales processes conducted by PG&E appear to have been intended primarily to meet a regulatory need, and were insufficient in both their design and administration to maximize the value of the products being sold from the portfolio.

a) **Sell Resources on a Long-Term Basis With All Value Intact**

It is readily apparent that the Joint Utilities should be evaluating and managing their portfolios from the perspective that their long-term bundled load customers’ requirements have been substantially and permanently reduced by load departures that range from 35 or 40 percent now up to 85 percent at some point into the future. But as discussed above, there is no evidence that the Joint Utilities have embraced that reality, whether in their departing load forecasting practices, in their resource planning and procurement decisions, or in their portfolio management decisions. It is time for the Commission to give the Joint Utilities explicit guidance and direction on steps they should be taking to correct those past mistakes.

First and foremost, the Commission should direct the utilities to engage in long-term forward sales transactions in order to flatten their substantially long (excess supply) positions and extract maximum long-term value for those resources. The short-term incrementalism in which the Joint Utilities are currently engaged is clearly failing to achieve these objectives.

457 Exh. CalCCA-3 at 3-1 to 3-5.
458 Exh. CalCCA-3 at 3-3:28 to 3-4:47.
459 Exh. IOU-1 at 1-1:19-28.
The Structured Portfolio Auction (SPA) proposal is CalCCA’s preferred approach to implement a long-term sale of portfolio attributes, and is the only alternative presented in this case that is reasonably designed to maintain, capture and maximize the long-term value of the resource attributes in the Joint Utilities’ portfolios. CalCCA urges the Commission to adopt the SPA proposal in concept and, in a subsequent phase of this proceeding, design and implement the detailed auction scope and protocols to permit the long-term sales to be achieved.

b) Sell Resources Subject to Reasonable Terms and Conditions.

Regardless of the means by which the resources are offered, the terms and conditions of the offers must be developed in a way that is most likely to maximize the interest of the market (including CCAs) and thereby maximize the value of the offering. Interest in the auction will be influenced by the way in which products are offered, including:

- The number of projects/contracts and type of resources being offered;
- Timing of RFO issuance and bid due dates relative to ongoing procurement schedules;
- Product structure, e.g., allowing for fixed price contracts with specified or preferred hourly delivery profiles to allow participants to capture the energy value for load hedging;
- Scope of information provided to develop detailed analysis of specific projects, e.g., information on P-Node locations to garner premiums based on geographic preferences, congestions issues, etc.

The utilities should solicit input from potential market participants to ensure ratepayers receive the highest price for the products offered to the market.460

460 Exh. CalCCA-1 at 3-14:9-24 (directly quoted).
c) **Require Revintaging of a Contract If the Utility Fails to Exercise a Right to Terminate the Contract or Otherwise Extends the Contract.**

The relevant departing load cost responsibility statutes require the Commission to assess charges only for procurement costs that are “unavoidable” by the utility acting on behalf of its customers. The Joint Utilities have encountered in the past, and will continue encounter in the future, opportunities to avoid costs under their PPAs will suppliers through the prudent exercise and leveraging of all contract rights and remedies to which they are entitled.461 Under such circumstances, departing load vintages require modification. If the utility is presented with an opportunity to end an existing contract obligation, that opportunity should mark a new procurement date because that procurement decision would not have been made on behalf of previously departed or imminently departing customers. Continuing to rely on the initial execution date to vintage the contract fails to acknowledge when an irrevocable decision has been made on behalf of a customer and the costs become “unavoidable.”462

**X. THE COMMISSION SHOULD DIRECT THE UTILITIES TO USE THEIR BEST EFFORTS TO REDUCE PORTFOLIO COSTS USING SECURITIZATION OF UOG ASSETS AND CONTRACT BUYDOWN TRANSACTIONS (Common Outline §VII)**

In the face of an estimated $49.68 billion in uneconomic portfolio costs over the next 22 years, the Commission and bundled and departing load customers have the right to expect the utilities to make all reasonable efforts – indeed, *best efforts* – to reduce their total portfolio costs. Yet only CalCCA, on behalf of its members’ ratepayers, proposed any material cost reduction measures in this proceeding. In addition to changes to optimize portfolio value, discussed in Section IX, CalCCA proposes two measures aimed at more significant, long-term savings.

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461 See id. at 3-15 to 3-16.
462 Exhibit CalCCA-1 at 3-15 to 3-16.
Material cost reductions could be achieved if the Joint Utilities refinanced their UOG assets through sales of low-interest bonds securitized by a dedicated rate component. These savings arise primarily from a reduction in financing costs from the utility weighted average cost of capital to the bond rates, levelization of the revenue requirement and a reduction in income taxes.463 As discussed below, this measure could produce PCIA-eligible cost savings, on a net present value basis, of $1.3 billion for PG&E and $589 million for SCE.464 In the first year, securitization could achieve a savings of $496 million for PG&E and $130 million for SCE compared with a traditional revenue requirement.465

Material cost reductions may also be achievable through buydown or price reductions in long-term PPAs. CalCCA proposes a voluntary reverse RFO, under which the utility, under Commission guidance, would invite offers for price reductions and select the offers providing the best value to the portfolio.466 As CalCCA witness Robert Kinosian explained, “[g]enerators may be willing to provide a significant reduction in the contract costs if they place a higher value than the utilities’ ratepayers do on an immediate payment rather than earn contracted revenues over time.”467 For example, “a reduction of $100 million/year for 20 years in contract payments provides ratepayers with a $2 billion nominal savings over 20 years.”468 Discounting these savings using the utilities’ weighted average cost of capital yields a net present value savings of approximately $1 billion to bundled and departing load customers.469

463 See Exh. CalCCA-1, Exhibit 3-A, Ex. K.
464 Exh. CalCCA-1 at 3-7:7-9.
465 See id., Exhibit 3-A. These values were derived, for PG&E, by comparing the 2019 revenue requirement values from Ex. I, p. 2 and Ex. H, p. 2 and, for SCE, by comparing the 2019 revenue requirement values from Ex. I, p. 3 and Ex. H, p. 2
466 Exh. CalCCA-1 at 3-9:8-16.
467 Id.
468 Exh. CalCCA-1 at 3-8:3-4.
469 Id. at 3-8:4-7.
Electric utility securitization has been used by investor-owned utilities as a taxable debt financing tool at least 64 times since 1997.\(^{470}\) Indeed, it is not a new concept in California. The Legislature and Commission have twice previously authorized the issuance of this type of debt.\(^{471}\) Both the Legislature and this Commission will easily be able to draw on these experiences as precedents for a new securitization program, updated to incorporate current best practices and examples set by other states.\(^{472}\) Facing roughly $50 billion in uneconomic portfolio costs for the next 22 years, the utilities should strongly be encouraged to make use of securitization to reduce the magnitude of these costs.

Assuming securitization is available to the utilities, it renders some portion of the current financing costs for UOG at the utility’s weighted cost of capital assets “avoidable.” Consequently, to the extent the utilities elect not to employ securitization, the Commission should reduce the return on UOG assets paid through the PCIA to the cost of debt, since only “unavoidable” costs may be recovered from departing load.

A. Securitization is a Low-Cost Financing Tool That Has Been Used in the Utility Industry

Securitization is a financing tool that has been used to facilitate several types of transitions in markets, and to eliminate rate “shocks” that could potentially have occurred in certain markets.\(^{473}\) “Securitization” describes a process by which a pool of assets that generate a cash flow, such as loans, credit card balances or other receivables, is used as collateral for a bond offering. In the utility context, the bond proceeds are used to meet retire a ratepayer obligation, such as generation asset rate base or a contract buydown. The cash flow securing the bonds,

\(^{470}\) Exh. CalCCA-1, Exhibit 3-A, at 6.
\(^{471}\) Exh. CalCCA-1, Exhibit 3-C, at 8-10.
\(^{472}\) 4 Tr. 691: 11-20 (Fischera).
\(^{473}\) 4 Tr. 664: 14-18 (Fischera); 4. Tr. 671: 1-25 (Sutherland).
typically a dedicated rate component in the utility context, is then used to pay principal and interest on the bonds.

For investor-owned electric utilities, securitization typically involves issuing highly-rated securities through special purpose, bankruptcy remote/ring fenced entities. In the unusual scenario, it is a specific legislatively enabled and regulatory approved process through which a special purpose legal entity (SPE), which is protected from any credit problems of the utility, receives from the utility the entire right, title and interest in certain assets that are that are then pledged to the repayment of the securities.\(^{474}\) The SPE, whose sole purpose is strictly limited to owning the pledged assets and paying the principal and interest on its bonds, issues securities backed by the transferred assets. The cash flows from those pledged assets are used to pay principal and interest on the bonds. The carrying costs of the securitized debt are much less than the costs that would be incurred using traditional utility financing methods of debt and equity, which is often called the utility’s “weighted average cost of capital” (WACC).\(^{475}\) Although the pledged assets can be physical (such as plant and equipment), frequently the asset transferred to the SPE is the collection by the utility of a commission-approved and periodically adjusted dedicated rate component.

The SPE and the securities it issues are perceived to carry much less risk than standard utility corporate debt and are therefore attractive to investors at a lower cost to the utility.\(^{476}\) To the investor, the bond issue is a direct borrowing on the utility’s customer rate base in its distribution territory without involving the utility’s balance sheet for credit purposes or

\(^{474}\) Exh. CalCCA-1, Exhibit 3-A, at 5.

\(^{475}\) Id. at 6.

\(^{476}\) Id.
comingling with the utility’s other creditors.\footnote{477} For the utility, securitization increases cash flow and achieves a lower cost of capital than traditional means. Securitization offers added benefits beyond the differences in the cost of capital. Because it reduces utility income, the process also reduces income taxes, including income-based state franchise taxes, as well as revenue-based local franchise fees. In addition, securitization levelizes debt carrying charges, shifting more costs into later years. This creates a NPV benefit.

In each state where utility securitization bonds have been issued, specific enabling legislation created in the utility the right to impose, adjust, bill and collect amounts from electric customers in a given service territory.\footnote{478} Then the relevant utility commission issued an irrevocable financing order imposing a specific charge on customers to implement the legislation. Because of this, the bonds have often been called ratepayer-backed bonds or ratepayer obligation charge (ROC) bonds and even rate reduction bonds (RRB), among other terms.\footnote{479}

Utility securitization bonds as described here are frequently confused with other types of “asset backed securities” (ABS). However, while there are common features, utility securitization bonds are generally considered much more “creditworthy” than typical ABS issues, and are decidedly unlike common ABS.\footnote{480} The major difference in creditworthiness is due to three factors: the regulatory nature of the asset in question, the ability for joint and several collection, and the nonbypassable feature of the charge that supports the debt.

\footnote{477}{Id.}
\footnote{478}{Exh. CalCCA-1, Exhibit 3-C, at 8.}
\footnote{479}{Id. at 6.}
\footnote{480}{Exh. CalCCA-1, Exhibit 3-A, at 13.}
Securitized utility bonds are backed by an enforceable regulatory right, not by a contract right or pool of receivables or other assets. This is an important distinction, and for this reason, the Office of Chief Accountant of the U.S. Securities and Exchange Commission (SEC) has directed that the type of securitized utility bonds under discussion here not be treated as “asset-backed securities” for purposes of Regulation AB (ABS offering regulations). In addition, unlike a general pool of assets supporting an issue of ABS, the regulatory asset created by the legislation is collectible from remaining customers even if some customers no longer receive electric transmission or distribution service, or fail to pay the charge. This again is a material difference. Finally, the legislation and the utility commission’s financing order create a nonbypassable charge to secure bond repayment. Generally, the financing order issued by the regulator is irrevocable and cannot be revisited at any time during the life of the bonds.

B. Securitization Reduces Portfolio Costs

Securitization saves money for utility ratepayers in several ways. First, the cost of equity is much higher than the cost of debt. In addition, securitized ratepayer-backed bonds pay lower interest than even traditional utility debt, due to their extremely high credit quality. With the SPE’s better credit rating, the bonds can be issued with a lower interest cost. For example and as detailed in CalCCA’s testimony, while PG&E’s authorized cost of equity is 10.25%, the securitization debt at current levels would likely bear an interest rate of only about 3.91%. In the case of SCE, the utility’s authorized cost of equity is 10.3%. Securitized debt, on the other

481 Id. at 11.
482 Id. at 14.
483 Id.
484 Exh. CalCCA-1, Exhibit 3-A, at 21.
485 Id.
hand, is estimated to likely cost only about 4.07%. These savings would accrue directly to the ratepayers in the form of lower overall rates than would otherwise be levied.

The second largest contributor to savings is in the avoidance of income taxes that would otherwise have to be paid on the equity return. When the Federal tax rate of 21% is combined with the 8.84% rate for California income-based franchise taxes, the effective composite income tax rate is 28%. With securitization financing, there are no income-based taxes. Because income related taxes are directly related to the utility earning a taxable equity return. With no equity, there will be no income tax payable. In addition, there are savings from the fact that revenue-based fees, such as local franchise fees, would be slightly less.

The third major contributor to savings is the levelization of the revenue requirements. Traditional ratemaking requires the ratepayer to pay much more in the early years of an asset’s useful life and much less in the later years. Securitization financing allows the ratepayer to pay a levelized amount throughout the life of the assets in question. By levelizing the payments that are financed with inexpensive debt rather than front-end loading revenue requirements, the NPV savings, when discounted at the utility cost of capital (7.69% and 7.61% for PG&E and SCE, respectively), are increased substantially. This accounts for about 23% of the $1.6 billion total NPV savings that is estimated for PG&E ratepayers. For SCE, levelization accounts for 15% of the $589 million total NPV savings.
In fact, the rating agency Moody’s has explicitly stated that securitization benefits the utility, as well as the ratepayers.\(^{493}\) Although the utility gives up the opportunity to earn a return on the corresponding asset, the utility receives an immediate source of cash, which it will simply invest in other ways.\(^{494}\) In addition to all of the benefits detailed above, securitization may offer greater potential benefits to PG&E and its customers in light of recent downgrades of its debt. PG&E could use lower-cost capital raised by securitization either in response to storm damage or wild fire response, or to pay down higher cost debt, thereby potentially causing its credit rating to increase as its debt-to-equity ratio decreases. The restoration and strengthening of PG&E as an investment grade company may be considered vital to the company’s future ability to service its customers.

C. Securitization of Utility Owned Generation Would Produce Substantial Cost Reductions for Bundled and Departing Load Customers

CalCCA proposes the Commission move forward with a program to securitize the rate base of all UOG intended to remain in the utilities’ PCIA-eligible portfolio for their remaining service lives. Securitization offers an opportunity to reduce the costs of resources in the utilities’ PCIA-eligible portfolios for all customers responsible for paying the PCIA, including bundled, community choice aggregation (CCA) and direct access (DA) customers.

Securitization would significantly reduce the cost to ratepayers in paying off the existing rate base as compared to the typical depreciation and cost of recovery process.\(^{495}\) Importantly, securitization would not change the ownership or operation of the facilities, which would continue to be owned and operated by the utilities. Aside from current rate base, additional costs

\(^{493}\) 4 Tr. 701: 4-10 (Abramson).
\(^{494}\) 4 Tr. 701: 4-10; 699: 27-28 (Abramson).
\(^{495}\) 4 Tr. 661: 24-28 (Fischera).
of the generation plants, such as fuel, O&M, A&G and capital additions, would continue to be
addressed in standard Commission proceedings and recovered under standard Commission
revenue recovery methods.\footnote{Exh. CalCCA-1, at 3-7.}

The proposal would be implemented through a bond issuance of capital sufficient to
repay the utilities for their remaining investment in their generation facilities, the generation rate
base, which is currently calculated at approximately $4.2 billion for PG&E and $1.5 billion for
SCE.\footnote{Id. at 3-6.} The current revenue requirements associated with the rate base (depreciation, WACC
and taxes on income) would be replaced by the lower interest and principal payments on the
securitized bonds. This would provide an initial estimated decrease in the amount charged to
bundled customers of more than 50%.\footnote{Id. at 3-7.} In addition to the direct savings to bundled customers,
the reduction in generation revenue requirements will also reduce the forecasted uneconomic
costs of the utilities’ generation portfolios, thereby reducing the PCIA.

If a securitization strategy were undertaken, cash realized by the utility could be used to
either pay down other, more expensive, utility debt, or to free up debt and equity capital for other
important projects, such as planned capital expenditures, emergency funds or extraordinary
expenses. The utility’s revenue requirement would decrease, resulting in savings to ratepayers.
Securitizing all or a portion of the exiting UOG rate base would reduce financing costs to all
ratepayers. Securitization of the utilities’ PCIA-eligible portfolios, excluding fossil intended to
be removed from this portfolio after 10 years under D.08-09-012, could produce PCIA-eligible
cost savings, on a net present value basis, of $1.3 billion for PG&E and $589 million for SCE.\footnote{Exh. CalCCA-1 at 3-7:7-9.}
In the first year alone, securitization would achieve savings for bundled and departing load customers of $496 million for PG&E and $130 million for SCE compared with a traditional revenue requirement.\textsuperscript{500}

\textbf{D. Voluntary Reverse RFO and Securitized Buydown of PCIA-Eligible PPAs Could Further Reduce Costs}

Much has been made elsewhere in this proceeding of the extreme decreases in the price of renewable energy, and the reasons behind the utilities’ entry into these now high-priced contracts. These are generally long-term contracts (some for 20-25 years) at set quantities and at set prices which now exceed current and expected future market prices. Some of these contracts call for the utilities to purchase power at rates as high as 18 cents/KWH or more.\textsuperscript{501} Encouraging price reductions in these contracts from willing counterparties in exchange for up-front payments, and securitizing the financing of these reductions, could materially reduce PCIA-eligible costs. The up-front, lump-sum amounts for the buydown would be paid off through securitization, as opposed to either expensing them in one year, which might result in rate shock, or having them paid off over time at the utility's rate of return.\textsuperscript{502} Securitizing contract buydowns, while less common than other types of securitization used with respect to utilities, has been used in other states. It was successfully implemented in New Hampshire and authorized for use in Vermont.\textsuperscript{503} It is a tested, successful method that could benefit California ratepayers.

\textsuperscript{500} See id., Exhibit 3-A. These values were derived, for PG&E, by comparing the 2019 revenue requirement values from Ex. I, p. 2 and Ex. H, p. 2 and, for SCE, by comparing the 2019 revenue requirement values from Ex. I, p. 3 and Ex. H, p. 2.

\textsuperscript{501} Id. at 28.

\textsuperscript{502} 4 Tr. 662: 9-14 (Fischera).

\textsuperscript{503} 4 Tr. 674: 21-25 (Sutherland); Exh. CalCCA-1, Exhibit 3-A, at 29.
CalCCA proposes that willing generators be paid an up-front lump sum in exchange for reducing the contract price for generation in future years, *i.e.* buying down the contract price.\textsuperscript{504} The funds used to pay the generators would come from the issue of securitized debt. The buydown may be extremely attractive to generators, who may be willing to provide a significant reduction in the contract costs, if they place a higher value than the utilities' ratepayers do on an immediate cash payment rather than earn contracted revenues over time. In financial terms, this is the case if the generators use a higher discount rate for discounting future cash flows than utility ratepayers.\textsuperscript{505} As CalCCA has proposed the process, the price reduction would be the only change, and all other terms of the PPA would remain in effect.

If, for example, an average price reduction of 13.5 cents per kWh for 2,000 GWh/year of purchased power was achieved by a buydown of eligible contracts (from 18.5 cents/kWh to 5 cent/kWh), it would, when netted against a levelized 20-year securitized bond payment of $187.6 million (9.4 cents/kWh), result in a net savings of $72.4 million (3.6 cents/kWh) in the first year.\textsuperscript{506} Such a restructuring could result in NPV savings to bundled, CCA and DA ratepayers of $449 million.\textsuperscript{507}

Additional savings may also be possible, depending on the generators’ willingness to accept a buydown, which will be driven in large part by each generator’s individual discount rate. Discount rates of 10% and 12% show a potential reduction of $850 million and $750 million respectively compared to the utilities’ weighted cost of capital.\textsuperscript{508} This disparity in buyer

\textsuperscript{504} Exh. CalCCA-1 at 3-9:8-16.
\textsuperscript{505} Exh. CalCCA-1, at 3-8.
\textsuperscript{506} Exh. CalCCA-1, Exhibit 3-A, at Exhibit P.
\textsuperscript{507} Id.
\textsuperscript{508} Id.
and seller discount rates provides potential opportunities for mutually beneficial, voluntary contract buydown transactions for existing RPS-eligible PPAs.

Securitization of contract buydown costs increases the potential for ratepayer savings with buydowns because the up-front payment would be financed at a rate much lower than the utilities’ weighted cost of capital, 3% to 4% compared to 7.5%. For example, if the developer’s discount rate is 15% and the utility’s securitized debt rate is 4%, there is a great deal of room for negotiation that would benefit ratepayers. There would be less room if the difference were that developer’s discount rate and the utility’s weighted average cost of capital of, say, 7.5%.\(^{509}\)

In addition to benefitting ratepayers, both buydown, and securitization of the buydown, of these contracts could also benefit the utilities in significant ways. In recent years, credit rating agencies have begun to analyze long-term PPAs as though they were, in part, debt of the purchasing utility. The Commission has studied the phenomenon\(^ {510}\) This exposes PCG/PCC&E and EIX/SCE to risk that the credit ratings on their other debt and equity securities will be reduced.\(^ {511}\) If the annual payment obligations of PG&E and of SCE are reduced by a buydown financed by a securitization, this “debt equivalence” concern should be significantly mitigated if PG&E’s and SCE’s.

In order to address certain concerns raised by commentators regarding a buydown solution, CalCCA proposes that a reverse Request for Offers mechanism be implemented to identify generators wishing to participate, and to provide for Commission-established metrics

\(^{509}\) Exh. CalCCA-1 at 3-9.
\(^{510}\) An Introduction to Debt Equivalence, California Public Utilities Commission, Policy & Planning Division, August 4, 2017.
\(^{511}\) Exh. CalCCA-1, Exh. 3-A, at 31.
and parameters applicable to the program.⁵¹² For example, the Commission could identify an amount of funding available for the RFO to buy down contract prices. The utility would then issue an RFO soliciting proposals from generators for contract price reductions. The generators offering the largest NPV discounts per dollar of upfront funding, perhaps subject to a floor set by the Commission, would be awarded a buydown.

Limiting negotiation to only price reduction per kWh, which should allay any ratepayer concerns about the utilities negotiating transactions without clear guidance and boundaries.⁵¹³ The program should be entirely voluntary, so no generators should feel compelled to modify their existing contracts. Because generators must compete with each other to ensure they are one of the winning bids, reasonable discounts are highly probable. Finally, CalCCA is proposing, as has been done in other states, that the authority to issue bonds be issued prior to the RFO.⁵¹⁴ Bonds themselves would be issued only if the RFO determines that there are bids offering saving significant enough for the buydown.⁵¹⁵ Thus, any potential concern regarding the unknown amount of savings is alleviated- the bonds will simply not be issued unless there are willing takers and the savings make sense for the state. The potential savings to all ratepayers by using securitization to fund a buydown of existing high-priced energy contracts merits robust consideration.

E. Limitations on the Utilities’ Ability to Employ Securitization Would Not Be Triggered by CalCCA’s Proposal

Certain commentators have raised concerns that securitization would negatively affect the utilities’ financing capacity. Although no figures were proposed for how much “capacity” is

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⁵¹² Id. at 3-9:5-8.
⁵¹³ Exh. CalCCA-1 at 3-:(5-8.
⁵¹⁴ 4 Tr. 682: 23-28; 683:1.
⁵¹⁵ Id.
required, or how much would be affected by securitization, concerns were raised that
securitization will affect the utilities’ “head room” to increase rates for other purposes.516 It has
also been stated that securitization should be “saved” in case it is needed to address other issues
the utilities may encounter 3 or 5 years from now, possibly as a result of major impacts to
infrastructure and the markets by climate change or other forces.517 However, any charge that
would be implemented due to UOG securitization as proposed by CalCCA would result in
approximately 5% of a total bill.518 This is four times less than the general rule of thumb used
that identifies charges of 20% or even 25% of a total bill as derogatory to financing capacity.519
Moreover, the amount of securitization proposed by CalCCA in this proceeding is much lower as
a percentage of utilities’ revenues, than was securitized successfully twice before.520 In
addition, given that the securitization CalCCA has proposed would itself lower the overall risk of
the utility, investors should consider it a benefit, not a negative.521

F. Securitization Examples

Other states have authorized the issuance of securitized bonds for investor-owned electric
utilities for a variety of reasons, the four primary reasons of which include efforts to: recover
operating costs incurred in the past for which future rate relief would be required, otherwise
resulting in sharp rate increases for consumers, recovery of costs for electric supply service
which are higher than the market, stranded costs’ recovery, and financing of increased
expenditures for new technologies requiring rate increases.522

517 4 Tr. 712: 11-12; 709: 15-23 (Patterson).
518 4 Tr. 687: 1-8 (Fischera).
519 4 Tr. 687: 19-26 (Fischera).
520 4 Tr. 688: 25-28 (Kinoshian).
521 4 Tr. 684: 1-6 (Abramson).
522 Exh. CalCCA-1, Exh. 3-D, at 5.
In Florida, the utility financed unrecovered costs of a nuclear plant that was retired early.523

In New Jersey, Maryland, Ohio, and West Virginia, regulatory assets representing deferred balances were securitized, while in Pennsylvania, Texas, New Hampshire, Illinois, Montana, Massachusetts, New Jersey, Michigan, Connecticut, and Louisiana, stranded costs in connection with electric industry deregulation were financed through this process. Storm recovery costs (Florida, Louisiana, Texas, Arkansas), costs of new pollution control equipment at existing electric generating facilities (West Virginia, Wisconsin), and costs of new renewable distributed generation (Hawaii) have also all been financed through securitization.524 The commissions in Texas, New Jersey, Michigan, Maryland, Louisiana, Ohio, West Virginia and Florida all have been actively involved in the structuring, marketing and pricing of securitized utility bonds.525

California itself already has a history of successful utility cost securitization efforts. Assembly Bill 1890 (Statutes of 1996, Chapter 854), California’s sweeping electric industry restructuring law enacted in 1996, authorized securitization for California’s investor-owned electric utilities.526 The legislature authorized the issuance of securitized Rate Reduction Bonds to finance a 10% rate reduction for residential and small commercial customers of California investor-owned utilities until they recovered the above-market costs of their generation-related assets. Pursuant to Financing Orders issued by the CPUC under authority of AB 1890, securitized Rate Reduction Bonds were issued for the benefit of PG&E ($2,901 million in 1997),

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523 Id. at 3.
524 Exh. CalCCA-1, Exh. 3-C, at 10.
525 Id. at 21.
526 Id. at 8.
SCE ($2,463 million in 1997), San Diego Gas & Electric Company (“SDG&E”) ($658 million in 1997) and Sierra Pacific Power Company ($24 million in 1999). 527

Then in January 2001, Governor Davis directed the state Department of Water Resources (DWR) to enter into contracts for the purchase and sale of electric power to assist in mitigating the effects of the emergency. 528 Under authority of the Governor’s proclamation, related executive orders, and legislation enacted in 2001, and pursuant to CPUC orders issued in response to that legislation, DWR implemented a program to supply to the customers of each utility the portion of their electric power not provided by that utility (the “Net Short”). DWR initially borrowed more than $10 billion to fund its purchases of electric power to cover the utilities’ Net Short. 529

In 2002, representatives of DWR and the CPUC executed a rate agreement under which the CPUC promised to impose and periodically adjust (i) a Power Charge to recover DWR’s ongoing power supply expenses; and (ii) a Bond Charge to produce revenues sufficient to pay scheduled principal and interest on Power Supply Revenue Bonds issued by DWR. 530 DWR issued Power Supply Revenue Bonds in several series to refinance much of the initial DWR borrowings. Those Power Supply Revenue Bonds have a final maturity date of May 1, 2022 and are payable primarily from Bond Charges. 531 In the rate agreement, the CPUC covenanted to calculate, revise, and impose Bond Charges sufficient to pay debt service on the Power Supply Revenue when due. DWR has pledged and assigned its revenues from Bond Charges for the payment of debt service on the Power Supply Revenue Bonds when due, subject to the possible

527 Id. at 8-9.
528 Id. at 9.
529 Id.
530 Id.
531 Exh. CalCCA-1, Exh. 3-C, at 10.
prior use of revenues from Bond Charges to pay amounts due under certain priority long-term power contracts.\footnote{532}

In 2005, the Public Utilities Code was amended to authorize PG&E to issue $3.0 billion of securitized energy recovery bonds to refinance a bankruptcy-related regulatory asset.\footnote{533} Securitization provided the necessary cash flow to allow PG&E to emerge from bankruptcy and over time gain a more favorable credit rating which would then reduce its cost of capital. Consumer groups proposed the refinancing of this “regulatory asset” with securitization, in essence giving the cash to PG&E up front in return for a reduced cost of carry for the regulatory asset. CPUC Decision No. 03-12-035 initially established that regulatory asset in the amount of $3.0 billion, with the proviso that the amount was to be reduced to the extent PG&E in the future received energy supplier refunds arising in connection with the 2000-2011 energy crisis.\footnote{534}

In its testimony CalCCA presented a set of “best practices” recommended for a securitization effort.\footnote{535} Many of these “best practices” concern the continued and active involvement of the utility commission in the authorization and monitoring of a security issuance. In fact, California’s prior history with securitization indicates the Commission’s expertise in implementing these practices. In the Financing Order (Decision No. 04-11-015) authorizing the issuance of Energy Recovery Bonds for PG&E, the CPUC was actively involved in the structuring, marketing, and pricing of past issuances of securitized utility bonds.\footnote{536} For example, the Financing Order included the following Ordering Paragraph 33:

\begin{footnotes}
\item[532] Id.
\item[533] Exh. CalCCA-1, Exh. 3-D, at 7.
\item[534] Exh CalCCA-1, Exh. 3-A, at 19.
\item[535] Exh. CalCCA-1, Exh. 3-C.
\item[536] Id. at 21.
\end{footnotes}
“Prior to the issuance of each series of Energy Recovery Bonds, the Bonds and the associated Bond transaction shall be reviewed and approved by the Commission’s Financing Team consisting of the Commission’s General Counsel, the Director of the Energy Division, other Commission staff, outside bond counsel, and any other outside experts that the Financing Team deems necessary. The other outside expertise may include, for example, an independent financial advisor to assist the Financing Team in overseeing and reviewing the issuance of each series of Bonds. The Financing Team’s approval of each series of Bonds shall be evidenced by a letter from the Financing Team to PG&E. Any costs incurred by the Financing Team in connection with its review and approval of each series of Bonds shall be treated as a Bond issuance cost.”

Using securitization to fund PPA buydowns is, as noted, not as common. It has been adopted as a preferred method. In Vermont in 1999 the Vermont Electric Power Producers (VEPP Inc.) attempted to buy down PPAs that were priced as high as 17.5 cents/KWH.537 Although the state legislature passed enabling legislation to authorize securitization for this purpose, VEPP Inc. was never able to execute the buy downs at prices that created ratepayer savings, and securitized bonds, therefore, were not issued. However, in April 2001 and again in January 2002, Public Service Company of New Hampshire issued Rate Reduction Bonds for reducing its capitalization and buying down high-cost PPAs.538

Given California’s successful history with utility cost securitization, CalCCA urges the Commission to proceed with either or both proposals. Whichever scenario the Commission, utilities and stakeholders elect to pursue, securitization will deliver value to ratepayers, the utility, and the state in reducing procurement costs and continuing to transition to a more competitive environment.

537 Exh. CalCCA-1, Exh. 3-A, at 29.
538 Id.
XI. OTHER ISSUES (Common Outline §VIII)

A. The Commission Should Authorize Prepayment of Departing Load Cost Responsibility

The current PCIA is volatile, difficult to forecast and not calculated in a transparent manner and monitoring the PCIA requires ongoing regulatory intervention. The Commission could address these challenges and bring certainty and predictability to CCA and DA customers by permitting CCA and DA providers to prepay all or a portion of their customers’ stranded cost obligation. Prepayment would entail an LSE paying the net present value of its future net obligations to the utility based on the LSE’s load and vintage. It would protect both CCAs and utilities from ongoing uncertainty regarding the amount and timing of stranded-asset cost obligations. LSEs considering formation could accurately assess and potentially finance their customer’s future obligations to the incumbent utility. The concept of Prepayment is also supported by AREM/DACC as set forth in Mark Fulmer’s testimony539.

A viable prepayment option requires a clear methodology that can be overseen and audited by the Commission to ensure indifference and transparency. To reduce burden on all customers, however, any reductions in outstanding liabilities should first be pursued. To that end, prepayment should occur only after the Commission and utilities act to reduce outstanding stranded asset costs and/or sell the underlying attributes at maximum value. After reasonable efforts have been made to reduce portfolio costs, the net present value of any future net costs in the CCA’s vintage would be used to calculate the prepayment amount.

The Joint Utilities concede that while the proposal would create certainty for both CCAs

539 Exh. AD-1 at IV.A.
and the Utilities\textsuperscript{540}, they allege that it would put undue risk on bundled ratepayers. However, if prepayment creates certainty for the utilities that certainty will necessarily flow through to the ratepayers and any methodology adopted by the Commission would be transparent and fair to all. In addition, as discussed below our proposal does not shift costs unfairly to bundled customers. Prepayment of departing load obligations have been successfully used in California in similar circumstances. This approach has also been used outside of the State in support of retail competition. These examples – highlighted below and as provided in Mark Fulmer’s testimony for AREM/DACC\textsuperscript{541} illustrate that it can be accomplished and has already been contemplated by the Commission. Together with the proposed Staggered Portfolio Auction\textsuperscript{542} determining the prepayment amount, this proposal provides potential frameworks to facilitate prepayment transactions.

1. **The Commission Has Previously Directed the Utilities to Permit California Publicly Owned Utilities to Prepay Departing Load Obligations**

In 2007, Commission Resolution E-3999\textsuperscript{543} directed the IOUs to offer bilateral agreements to publicly owned utilities (with departing load customers) as an alternative to the Municipal Departing Load tariff. The Commission rejected the utilities’ proposal to collect the full, undiscounted expected value of the CRS and other NBCs, plus an additional 2\%, as unfair and inconsistent with Commission precedent. Instead, PG&E and SCE were directed to calculate a lump-sum payment based on the net present value of all future CRS and other NBCs.\textsuperscript{544}

\textsuperscript{540} Exh. IOU-3 at 7B-33
\textsuperscript{541} Exh. AD-1 at IV.C.
\textsuperscript{542} See Section VI. B.
\textsuperscript{543} Resolution E-3999, available online at: http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_RESOLUTION/62648.PDF.
\textsuperscript{544} The calculation of a net present value requires use of a discount rate. In this proceeding, the Commission used the IOU’s weighted cost of capital. Use of other discount rates may be appropriate depending on the type of obligation being paid off. For example, IOUs do not make any profits or return.
Following this Resolution, PG&E and SCE entered into bilateral agreements with eight POUs: Power and Water Resource Pooling Authority, Merced Irrigation District, Modesto Irrigation District, Turlock Irrigation District, and the Cities of Azusa, Rancho Cucamonga, Moreno Valley, and Victorville. Only three of the eight POU agreements have publicly available costs. Those costs range from a low of $1.5 million under Modesto Irrigation District’s agreement to a high of $6.9 million under the Turlock Irrigation District’s agreement in 2016. These LSEs each have over 100,000 customer accounts, and a load of 2,503 GWh and 2,000 GWh, respectively. In 2009, D.09-08-015 expressly concluded that the PG&E/PWRPA agreement fully satisfied the departing load obligations of PWRPA’s customers, and that PG&E had no right to seek further payment or pursue any claim against PWRPA’s customers for charges under PG&E’s departing load tariff. Thus, the Commission has previously approved an agreement that resolves past, present, and future nonbypassable charge obligations through payments of amounts that may differ from tariffed charges.

2. Commercial Customers Have Prepaid Bundled Service Obligations When Departing Utility Service in Neighboring States

Like California, Nevada has an RPS requirement (25% by 2025), additional renewable procurement required by legislation, and requires Commission approval for new generation. Recognizing these obligations, MGM resorts in Nevada left bundled service from Nevada Power Company in 2015 for a lump-sum payment of $87 million and Switch, a data center company, departed utility service on payment of a $27 million exit fee.

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from the purchased power contracts, thus use of the weighted cost of capital may not be the appropriate metric. The ability to securitize these obligations would also affect the appropriate discount rate.

Source, 2016 EIA data. Available at: https://www.eia.gov/electricity/data.php#sales.

D.09-08-015, available at: http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/105902.PDF.
MGM represented 4.86% of Nevada Power Company’s annual sales with 59 accounts at 19 different locations. In the buyout, the Public Utilities Commission of Nevada (PUCN) directed Nevada Power Company to perform production cost simulations to show the total costs with, and without, MGM. The Nevada Commission directed Nevada Power Company to include resources required by legislation procured while MGM was a customer, but to exclude future compliance obligations and “placeholder resources” not seeking specific approval. In addition, the PUCN directed NPC to include O&M savings resulting from reduced operation due to MGM’s departure. The net present value of all costs and savings were calculated based on NPC’s weighted average cost of capital.547

Switch was initially denied the ability to exit by the PUCN on the grounds that it violated the principle of indifference by failing to allocate a share of legislated energy policies into the exit-fee calculation. The PUCN later reconsidered this decision, and unanimously voted to grant Switch permission to depart service after paying a $27 million exit fee.548

There are other examples of a departing corporate customer and the incumbent utility agreeing to lump-sum buyout terms. In 2016, Puget Sound Energy and Microsoft jointly filed an Advice Letter with the Washington Utilities and Transportation Commission recommending adoption of a tariff which would grant Microsoft the ability to procure its own generation and only take transmission and distribution service from Puget Sound Energy.549 In that case, the two entities agreed upon an exit-fee of $23.9 million.

547 See Public Utility Commission of Nevada docket 15-05017 for MGM Application, testimony, and Staff response.
548 See Public Utility Commission of Nevada docket 16-09023 for documents related to the Switch Application.
549 See Washington Utilities and Transportation Commission docket UE-161123 for the Settlement Agreement and Order approving the Settlement.
While the Joint Utilities contest that these examples are not analogous to the situation at hand, we respectfully disagree. These western region examples, when viewed in light of a regional trend toward departing load, show how utility and consumer concerns have been successfully and adequately addressed in other instances. In addition, as AREM/DACC states in its testimony, each IOU already has in its New Municipal Departing Load tariff the option to have the PCIA and other departing load obligations paid as a negotiated lump sum.550

3. The Prepayment Calculation Could Rely on Values from the Staggered Portfolio Auction or as a Result of Bilateral Negotiation Subject to Commission Approval

After using a Reverse Auction for voluntary offers by sellers, securitization of a portion of the IOU portfolio, and performing a Staggered Portfolio Auction to reallocate resources and create a benchmark, prepayment could be used to address remaining resources and corresponding stranded-cost liabilities. A prepayment option preserves indifference and provides a path for LSEs to reduce volatility and protect their customers from rate shock. To calculate a prepayment value, two inputs must be determined: (1) the NPV of the future stream of costs for resources within the customer’s vintage and, (2) the current market value of these resources. To calculate the NPV of future costs, the total amount of remaining obligations over the life of existing contracts should be aggregated by year and discounted at an appropriate rate. This will provide the total obligation – in today’s dollars – on a per-customer basis.

The Staggered Portfolio Auction551 could provide valuable information to determine the current market value; for the full host of attributes contained in various categories of resources with varying terms. Bundled ratepayers and other departing load customers sharing portfolio

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550 Exh. AD-1 at IV.C 27-28.
551 See Section VI.B.
obligations would be protected from an unreasonably low prepayment price through the use of a floor price in the SPA. Alternatively, direct bilateral negotiation, subject to Commission approval, as the utilities did for the eight POUs mentioned above, could identify the fair value of the remaining obligations. Once a fair value has been established, LSEs would have the option to prepay all or a portion of their vintaged obligation for various resource types using resource categories that match those used in the auction.

The Commission recently recognized prepayments as a method to preserve indifference in the context of Resource Adequacy. Resolution E-4907,\textsuperscript{552} which stipulated terms for a transfer of RA from a utility to an LSE found that one of two conditions was necessary to preserve indifference: (1) a bilateral agreement between the utility and CCA, or (2) a Commission-calculated weighted average capacity cost which the CCA would have to pay. The Commission reasoned that neither LSE would enter into an agreement that would harm its customers under the first scenario, and that the Commission could calculate the weighted average capacity cost of RA under the second.

4. Prepayment Would Not Shift Costs Among Bundled and Departing Load Customers

The Commission has an obligation to ensure that prepayment, like the calculation of the PCIA, does not shift costs among bundled and unbundled customers. There are two potential types of cost shift: (1) from the prepaying customers to bundled customers, and (2) from a prepaying customer to other departing load customers. The availability of actual, contemporaneous sales prices for similar products for a similar term could help calculate the prepayment amount and substantially reduce the risk of cost shifts. The prepayment terms

\textsuperscript{552} Resolution E-4907, available online at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M210/K016/210016662.PDF
should mirror the payment obligations for PPAs and UOG resources included in the portfolio of resources for which the prepayment is being applied.

The Joint Utilities argue that prepayment is inherently at odds with the concept of indifference and would place departing load customers at risk. Yet every forecast that is made, whether in procurement or ratemaking, risks being too high or too low. A retroactive look at any commercial transaction several years after it has taken place – with access to information not available at the time of transaction – may lead one party to make a different choice if they could travel back in time. But as market participants inherently understand, all transactions are made based on the best available information at the time, not what parties have learned since. Every time an IOU enters into a long-term contract, its ratepayers are subject to the risk that the IOU may have made a commitment that might turn out to be ill-advised. In every long-term contract the IOU might also realize an unforeseen windfall benefit as it avoids future market spikes. In addition as AREM/DACC states in its testimony, allowing prepayment allows customers the flexibility to more easily switch among competitive retail sellers while also foreclosing on the opportunity for refunds, thereby providing certainty for both parties.

B. PCIA Caps and Sunsetting of Cost Responsibility Merit Consideration

1. The Commission Should Permit Parties to Request Rate Caps in Forecast ERRA Proceedings If Circumstances WARRANT

CalCCA members place a high value on predictability and stability in the PCIA rate from year-to-year. The current annual fluctuation of PCIA charges makes planning efforts difficult, in particular efforts to pursue clean resource development objectives. One stabilizing tool that can be used and has been utilized by the Commission in the past is a rate cap. A cap provides

553 Exh. IOU-3 at 7-13.
554 Exh. AD-1 at 5:3-4.
assurances to both the CCA and its customers that costs outside of the CCA’s control – the PCIA rate – will not result in rate shock or otherwise interfere with procurement planning.

The Commission has adopted rate caps both in the context of rate cases and stranded cost responsibility. In SCE’s GRC Phase II Rate Case,\textsuperscript{555} the Commission adopted a settlement capping rate increases to 3\% for distribution revenues and 2\% for generation revenues in order to avoid rate shock and to transition more moderately to cost-of-service rates.\textsuperscript{556} A fixed rate cap of 2.7\textcent/kWh on the DA CRS was also adopted by the Commission in response to concerns that the level of CRS imposed on DA risked making DA uneconomic.\textsuperscript{557} In both cases, costs above and below the cap were netted in a balancing account to ensure full cost recovery over time.\textsuperscript{558}

CalCCA sees the potential value in a rate cap, depending upon the evolution of the PCIA rate but does not propose a cap at this time. While other parties in this proceeding, including TURN\textsuperscript{559} and AREM/DACC\textsuperscript{560} do propose the adoption of a cap on year-to-year changes in PCIA charges here, if the Commission declines to do so. CalCCA requests, that the Commission establish the opportunity for parties to evaluate the need for and to propose a rate cap in each annual Forecast ERRA. The Joint Utilities argue that the ERRA is not the appropriate forum,\textsuperscript{561} but instead seemingly concede that any cap should be addressed in this proceeding via a Petition for Modification.\textsuperscript{562} This objection ignores the fact that the Commission can modify any prior

\textsuperscript{555} A.14-06-014.
\textsuperscript{556} D.16-03-030 at 11. The Decision acknowledges that “Capping…of allocated revenues to rate groups…promote[s] rate stability while achieving movement towards cost-based rate levels.”
\textsuperscript{557} D.02-11-022, Ordering Paragraph 19 at 109.
\textsuperscript{558} Id. at 24-27.
\textsuperscript{559} Exh. TURN-1 at 11-14
\textsuperscript{560} Exh. AD-1 at 5:5-15
\textsuperscript{561} Exh. IOU-3 at 5-12:23-33.
\textsuperscript{562} Id. at 5-13:1-3
decision in this rulemaking, permitting parties to request caps in the future if circumstances support their adoption.

2. **The Commission Should Consider Establishing a Fixed Sunset Date or Trigger Event for Sunset of the PCIA**

Non-utility LSEs share frustration with the continuing presence of stranded procurement costs and the related surcharges. Some ESPs have been dealing with stranded procurement costs – whether the CTC, DWR Power Charge or the PCIA – for two decades. Yet there is no clear end in sight. AB 117 makes clear, for example, that a CCA customer will bear cost responsibility for “net unavoidable costs” of purchase contracts until these contracts expire or are terminated; many of these contracts have terms of up to 25 years or longer.\(^563\) Seemingly every new piece of legislation, most recently SB 350,\(^564\) offers some version of stranded cost responsibility. While the underlying motivation for these provisions is understood – preventing cost shifts – the dynamics surrounding the stranded cost problem must be addressed for stranded costs to fully sunset.

The Commission should make a finding in this case regarding the establishment of a defined sunset date for these stranded costs. Constraints on stranded cost recovery, such as the limitation on CTC recovery pursuant to AB 1890, reflect a legitimate viewpoint that transitions should not be open-ended but should be subject to defined limits around the time, scope and magnitude of above-market cost recovery. A fixed time limit on departing load cost recovery, to the extent permitted by law and consistent with other state policy goals, would provide greater certainty and flexibility to CCAs in building the optimal portfolio to meet their customers’ needs. Consistent with the other arguments CalCCA has made herein, certainty in the market helps

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564 Cal. Pub. Util. Code §740.12(c)
entities plan and pursue resource goals. A defined sunset would go a long way to providing this certainty.

C. The Commission Should Require the Utilities to Formalize the Approach Used in this Rulemaking for Long-Term PCIA Forecasting in ERRA Proceedings

A key objective for CalCCA in this proceeding is the implementation of a reasonable, transparent, and repeatable process for forecasting long-term PCIA rates for use among the various parties. A realistic long-term PCIA rate forecast would be supportive of CCAs’ overall business planning, procurement decision making, portfolio risk management, ratesetting and other related operational functions. CalCCA believes there is a workable path for the Commission, building upon the insights gained and work completed in this proceeding, to define a process of maintaining and continually refreshing a long-term forecast of PCIA rates.

Under the CCA proposal, the utilities would leverage the work done in this case to build and maintain a model capable of presenting reasonable projections of PCIA eligible portfolio cost value metrics. The CCA proposal would:

- Formalize the approach embodied in the “ALJ Data Matrix” to project long-term (10-years or longer) projections of the Generation Volumes (in GWH) and Total Cost (in $) of all resources in their PCIA-Eligible portfolios.
- Require the utilities to provide annual updates of these long-term projections as part of their annual ERRA Forecast filings.
- Provide a section of the model for parties to input forward market price curves of their own choosing, upon which to calculate the Market Value and Net Costs (Total Costs in excess of Market Value).

The availability of this information will allow parties’ reviewing representatives to calculate long-term projections of the Indifference Amount and Indifference Rate (differentiated by rate class and vintage). The information should be made available to parties under the Modified NDA developed in this proceeding to cover access and use of this material.
An alternative should be made available for parties who are unable to designate a reviewing representative under the Modified Non-Disclosure Agreement (MNDA). These parties should be permitted to provide a forward price curve to the utility and have the utility generate the long-term PCIA forecast for their vintage.

CalCCA believes that formalizing this approach, building on work that has been proven workable and highly valuable in this proceeding, provides a reasonable opportunity for all parties to gain the benefit of long-term PCIA forecasting while minimizing the burden on the utilities. The Joint Utilities argue that such an approach is an unreasonable and unjustified burden and not supported by law and instead suggests basing the forecasting methodology on the specific data required to develop a long-term forecast under the particular cost allocation method the Commission ultimately adopts in this proceeding. The Joint Utilities object to the use of the MNDA for providing the information proposed by CalCCA or a limited waiver of the Commission’s confidentiality rule.  However, Guiding Principle 1(a) states that the PCIA methodology “should be transparent and verifiable, including the most open and easily accessible treatment of input data, while maintaining confidentiality of information that should remain confidential.” The utilization of the MNDA (or another form of NDA agreed upon by the parties) strikes a sufficient middle ground whereby the interested parties get the information they need while maintain confidentiality of that information as it relates to the public at large.

The Joint Utilities also allege that the CalCCA proposal conflicts with the Guiding Principle that LSEs should be responsible for power procurement activities performed on behalf of their customers, but does not fully explain how the CalCCA proposal violates Guiding

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565 Exh. IOU-3 at 6:4-12.
566 Scoping Memo at 13-14
Principle 1(f). This guiding principle provides that “Any PCIA methodology adopted by the Commission to prevent cost increases for either bundled or departing load: should allow alternative providers to be responsible for power procurement activities on behalf of their customers, except as required by law.” CalCCA believes that the proposal does not violate the guiding principle, but instead creates a means for LSEs to manage portfolios with more certainty. The Joint Utilities cannot reasonably argue that CCAs should pay as much as 85% of PCIA-eligible costs absent the reasonable transparency requested here.

D. The Commission Should Require the Joint Utilities to Separately Identify Uneconomic Costs as a Line Item on Bundled Customers’ Bills

The PCIA rate reflects the uneconomic costs of utility procurement and is charged to bundled, CCA and DA customers. Even though all customers, including the utility’s bundled customers, pay for the uneconomic costs reflected in the PCIA, the charge is not separately identified on the Energy Statements provided to bundled customers. In contrast, the PCIA rate is separately identified on the Energy Statement provided by PG&E to CCA or DA customers, allowing a distinction between the CCA or DA supplier’s costs and the customer’s share of the utility’s uneconomic costs.

The current utility bill presentation masks the fact that all customers are应该ering the burden of the utility’s uneconomic costs. Today, a customer who performed a side-by-side comparison of billing formats would observe that the CCA bill includes a rate that is not present on the bundled service bill. Without explanation, customers might erroneously conclude that CCA customers are required to pay additional costs not included in bundled service. This need for greater transparency is a acknowledge by the Joint Utilities in their rebuttal testimony

567 Exh. IOU-3 at 6:11-12.
568 Scoping Memo at 14.
The Commission should direct the utilities to modify this practice, requiring separate identification, using the same terminology, of the component of all customers’ rates that recovers uneconomic costs. Applying the charge similarly on all bills prevents this charge from becoming a competitive issue when comparing alternatives and makes clear that all customers – bundled, CCA and DA customers – are sharing this cost responsibility and allows all customers to compare their options equally. Operationally, this will also reduce confusion in a scenario in which customers can move back and forth between bundled and un-bundled service.

Recognizing that the uneconomic cost portion of the rate is not an “indifference adjustment” when applied to a bundled customer, the PCIA rate and the bundled customer analog should be labeled more descriptively. We recommend labeling the charge the “Electricity Provider Transition Charge.” The Joint Utilities agree that transparency is needed stating in their rebuttal testimony that “greater transparency can and should be achieved through modifications to both utility tariffs and customer bill formats.” However, they argue that it could take considerable time to change the Utilities billing systems. Therefore the Commission should order the Joint Utilities to set forward on the path towards revising bill formats for more clarity as described above and set forth a process for achieving such a goal. The workshop process proposed by the Joint Utilities in 2019 could be used to accomplish this goal; however the Commission should set a deadline for implementation.

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XII. CONCLUSION

For all of the foregoing reasons, CalCCA requests that the Commission adopt the proposals set forth herein.

Respectfully submitted,

Evelyn Kahl
Counsel to the
California Community Choice Association

June 1, 2018