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Ratesetting****TO PARTIES OF RECORD IN RULEMAKING 17-06-026:**

This is the proposed decision of Administrative Law Judge Roscow. Until and unless the Commission hears the item and votes to approve it, the proposed decision has no legal effect. This item may be heard, at the earliest, at the Commission's September 13, 2018 Business Meeting. To confirm when the item will be heard, please see the Business Meeting agenda, which is posted on the Commission's website 10 days before each Business Meeting.

Parties of record may file comments on the proposed decision as provided in Rule 14.3 of the Commission's Rules of Practice and Procedure.

The Commission may hold a Ratesetting Deliberative Meeting to consider this item in closed session in advance of the Business Meeting at which the item will be heard. In such event, notice of the Ratesetting Deliberative Meeting will appear in the Daily Calendar, which is posted on the Commission's website. If a Ratesetting Deliberative Meeting is scheduled, *ex parte* communications are prohibited pursuant to Rule 8.3(c)(4)(B).

/s/ ANNE E. SIMONAnne E. Simon
Chief Administrative Law JudgeAES:avs
Attachment

Decision PROPOSED DECISION OF ALJ ROSCOW (Mailed 8/1/2018)

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.

Rulemaking 17-06-026

**DECISION MODIFYING THE POWER CHARGE
INDIFFERENCE ADJUSTMENT METHODOLOGY**

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DECISION MODIFYING THE POWER CHARGE INDIFFERENCE ADJUSTMENT METHODOLOGY

Summary

Communities throughout California are evaluating and launching Community Choice Aggregation (CCA) programs at a growing rate. CCA programs allow communities to provide electricity to customers within their boundaries, replacing the regulated electric utilities as their provider. In light of the growing trend toward formation of CCAs, the electric utilities subject to the jurisdiction of this Commission are experiencing a widening disparity between the level of resources in their portfolios and what is required to serve the reduced load after customers depart for CCA service. This customer movement has also led to corresponding changes in California's electric procurement market as CCAs expand their portfolios, compounding the challenges of ensuring that customer departure from utility service is facilitated consistently with the statutory framework supporting CCA formation. That framework requires the Commission to ensure that departing customers remain responsible for certain costs incurred on their behalf by their utility, without being subject to costs that were not incurred on their behalf. Similar requirements govern other programs that allow some utility customers to engage in "direct access" transactions for their electricity supply, again replacing utility supplies.

This proceeding was initiated to respond to widespread concerns that the Commission's existing cost allocation and recovery mechanism is not preventing cost shifting between different groups of customers, as required by law, and is therefore not in compliance with the statutory frameworks that (1) authorized customers to engage in direct access transactions for electricity and (2) provided for formation of CCAs. This decision refers to these customer groups collectively

as “departing load customers” and to the customers who continue to take service from their electric utilities as “bundled load customers”.

In this decision the Commission adopts revised inputs to the market price benchmark (MPB) that is used to calculate the Power Charge Indifference Adjustment (PCIA), the rate intended to equalize cost sharing between departing load and bundled load. The revised methodology will be used to calculate the PCIA that takes effect as of January 1, 2019. We also open a second phase of this proceeding to consider the development and implementation of a comprehensive solution to the issue of excess resources in utility portfolios. We expect that solution to be based on a voluntary, market-based redistribution of excess resources in the electric supply portfolios of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company.

In addition to the revised MPB inputs, this decision also adopts an annual true-up mechanism, as recommended by a number of parties, as well as a cap that will limit the change of the PCIA rate from one year to the next. The true-up will ensure that bundled and departing load customers pay equally for the above-market costs of PCIA-eligible resources. The cap will provide a degree of the rate stability and predictability sought by parties representing departing load interests. Finally, we take an additional step toward the simplicity and predictability requested by departing load customers by adopting an option for these customers to pre-pay their PCIA obligation.

A second phase of this Rulemaking shall be initiated in order to enable parties to continue working together to develop longer-term solutions.

This proceeding remains open.

1. Background

The Commission opened this Order Instituting Rulemaking (OIR or Rulemaking) to review the current Power Charge Indifference Adjustment (PCIA). The PCIA that is in place today originated in statute enacted during the 2001 California energy crisis when the California Legislature passed Assembly Bill (AB) 1X. After finding that “a number of factors have resulted in a rapid, unforeseen shortage of electric power and energy available in the state and rapid and substantial increases in wholesale energy costs and retail energy rates, with statewide impact, to such a degree that it constitutes an immediate peril to the health, safety, life and property of the inhabitants of the state”, the Legislature declared that “the public interest, welfare, convenience and necessity require the state to participate in markets for the purchase and sale of power and energy.”¹ AB 1X authorized the state Department of Water Resources (DWR) to enter into contracts for the purchase of electric power for delivery to retail customers of Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E). In the same legislation, the Legislature directed the Commission to suspend the right of customers to enter into direct access (DA) transactions with non-utility providers of electricity.

It soon emerged that the new DWR contracts were extremely expensive relative to post-crisis electricity costs. This prompted many customers that had been returned to bundled service by their DA providers during the crisis to reverse course and resume DA service. The Commission noted that DWR had made purchases on behalf of these DA customers as well as those bundled

¹ AB 1X ((Stats. 2001 (1st Extraordinary Sess.), ch. 4).

service customers who later entered into DA contracts or arrangements.² For this reason, the Commission determined that there would be a significant magnitude of cost-shifting if energy crisis costs were borne solely by bundled service customers but DA customers were not required to pay a portion of these costs.³

For these reasons, the Commission ordered that “direct access surcharges or exit fees shall be developed [...] so that there is an equitable allocation of the DWR costs and other costs that may be considered, and that direct access customers pay their fair share of DWR costs and non-DWR costs and bundled service customers are indifferent.”⁴ The Commission then adopted a “cost responsibility surcharge” (CRS) intended to recover the relevant costs covered by its directive. As initially adopted by the Commission, the CRS incorporated (1) a DWR power charge to collect ongoing contract costs, (2) a DWR Bond Charge to pay for significant costs incurred during the height of the crisis, and (3) an ongoing competition transition charge (CTC) whose purpose was to recover statutorily-authorized costs related to the restructuring of California’s electric industry that occurred prior to the energy crisis.⁵

Also in 2002 the Legislature passed and the Governor signed into law Assembly Bill (AB) 117, which authorized the creation of Community Choice Aggregators (CCAs). CCAs are governmental entities formed by cities, counties,

² Decision (D.) 02-03-055 at 9-10. The Commission noted that direct access share of total utility load dropped to about 2% by June 2001, then reversed such that between July 1, 001 and September 20, 2001, approximately 11% of the total electric load of the utilities had shifted from bundled service to direct access service.

³ *Id.*, Finding of Fact 3.

⁴ *Id.*, Ordering Paragraph 3, as modified by D.02-04-067.

⁵ D.02-11-022 at 3-4.

or a combination of cities and counties, in order to serve the energy requirements of their local residents and businesses. AB 117 clarified Legislative intent regarding cost recovery and cost shifting by adding Section 366.2 (d)(1) to the Public Utilities Code, describing it as “declaratory of existing law”:

It is the intent of the Legislature that each retail end-use customer that has purchased power from an electrical corporation on or after February 1, 2001, should bear a fair share of the [DWR’s] electricity purchase costs, as well as electricity purchase contract obligations incurred as of the effective date of the act adding this section, that are recoverable from electrical corporation customers in commission-approved rates. It is further the intent of the Legislature to prevent any shifting of recoverable costs between customers.

The Commission acknowledged this legislative intent in its decisions implementing AB 117, but also articulated a counterbalancing precept that continues to guide Commission policy-making:

The objective of AB 117 in requiring CCAs to pay a CRS is to protect the utilities and their bundled utility customers from paying for the liabilities incurred on behalf of CCA customers. Our complementary objective is to minimize the CRS (and all utility liabilities that are not required) and promote good resource planning by the utilities.⁶

These basic principles regarding overall cost minimization and prevention of cost shifts between customers have remained in place since the beginning of legislative and Commission efforts to equitably address the cost responsibility issues regarding departing load. However, more recent legislative direction reemphasizes that the Commission must ensure equity on both sides of the

⁶ D.04-12-046 at 29.

departing load transaction, that is, for departing load as well as remaining bundled IOU load. In 2011, Senate Bill (SB) 790 added the requirement that the cost responsibility of CCA customers shall be reduced by the value of any benefits that remain with bundled service customers, unless the CCA customers are allocated a fair and equitable share of those benefits.⁷ Most recently, in 2015 SB 350 added Sections 365.2 and 366.3 to the Public Utilities Code, which make explicit the dual requirements that (1) bundled service IOU customers do not experience any cost increases when other retail customers elect to receive service from other providers, or due to the implementation of a CCA program, and (2) customers who depart for another provider or due to formation of a CCA do not experience any cost increases due to an allocation of costs that were not incurred on behalf of the departing load:⁸

Section 365.2 provides that:

The commission shall ensure that bundled retail customers of an electrical corporation do not experience any cost increases as a result of retail customers of an electrical corporation electing to receive service from other providers. 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.

Section 366.3 provides that

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

⁷ Stats. 2011, ch. 599 (amending Pub. Util. Code § 366.2)

⁸ Stats. 2015, ch. 547.

cost increases as a result of an allocation of costs that were not incurred on behalf of the departing load.

The statutory developments summarized above have been paralleled by increased interest in PCIA matters by parties participating in Commission proceedings. The Commission's efforts to implement legislative intent reached an initial period of stability in 2006, when the Commission replaced the original CRS with the current PCIA-based methodology.⁹ As the Commission explained,

The PCIA is intended to preserve the indifference concept adopted in D.02-11-022 for DA customers who pay the DWR power charge component of CRS. To accomplish this intent, the cost responsibility for ongoing CTC and the PCIA charge for DA customers who pay the DWR power charge would equal their responsibility under the indifference rate concept [plus recovery of franchise fees].¹⁰

The PCIA-based methodology reflected a consensus recommendation of IOU, direct access and customer-group parties active at that time. Its central feature was a revised calculation of the required "indifference amount" that compared each utility's total power portfolio costs, expressed in cents/kWh, to a market benchmark comprised of the posted forward prices for a one-year strip of power for the coming year, plus a capacity adder to reflect the cost of resource adequacy (RA). In this manner, the RA benefits of generation resources acquired to meet system or local area reliability needs were reflected in the value allocated among customers.

The Commission subsequently adopted two additional refinements to the PCIA methodology, resulting in the current version that we review in this

⁹ See, D.06-07-030.

¹⁰ *Id.* at 25.

decision. First, D.11-12-018 adopted a revised capacity adder and increased the market price benchmark by adding a renewable procurement standard (RPS) adder, which accounted for new RPS requirements, and the fact that contracts executed to satisfy the RPS requirements would be relatively more expensive than other conventional generation. Second, the scope of CCA and DA cost responsibility broadened in 2014, when the Commission authorized the recovery of the utilities' energy storage procurement costs through the PCIA.¹¹

The Commission now adopts annual values for the PCIA for PG&E, SCE and SDG&E in each utility's annual Energy Resource Recovery Account (ERRA) forecast proceeding. In the years since adoption of the PCIA methodology, dissatisfaction has grown among all parties with a stake in the outcome--both with the process of calculating the PCIA, and with its numerical outcomes. In March, 2016 the Commission's Energy Division hosted a workshop regarding these issues and issued a workshop report in September, 2016. The Commission noted that among a number of issues raised at the workshop, the main concerns expressed by DA and CCA parties focused on the transparency of PCIA calculations and uncertainty about the level of the PCIA over time.¹² The Commission directed that a PCIA working group led by Sonoma Clean Power and SCE, with participation from other interested groups, address issues regarding improved transparency and certainty.¹³ The working group met a

¹¹ D.14-10-045, Ordering Paragraph 1.

¹² D.16-09-044 at 19.

¹³ *Id.*, at 20 and Ordering Paragraphs 7 and 8.

number of times and submitted its final report on April 5, 2017.¹⁴ Many of the participants in the working group are parties in this rulemaking.

1.1. Procedural Background

Pursuant to Rule 7.1(d) the June 29, 2017 OIR included a preliminary scoping memo that provided a set of preliminary guiding principles for this proceeding and preliminarily determined the issues to be considered by the Commission. The OIR also directed that all respondents must file comments in response to the OIR, and provided that other interested persons may file comments as well.¹⁵ On July 24, 2017 the Commission received comments from 28 entities or groups.

The initial prehearing conference (PHC) took place on August 31, 2017 and the Scoping Memo and Ruling of Assigned Commissioner Peterman (Scoping Memo) issued on September 25, 2017. The Scoping Memo specified the issues that are within the scope of this proceeding, determined that this is a ratesetting proceeding for which hearings would be necessary, set forth the schedule, assigned the presiding officer, and resolved other procedural matters.

On February 7, 2018 a number of parties filed a joint motion to extend the procedural schedule. On March 2, 2018 the Amended Scoping Memo and Ruling of Assigned Commissioner (Amended Scoping Memo) established a revised

¹⁴ As a result of the working group process, SCE, PG&E and SDG&E and representatives of several CCAs jointly submitted a Petition for Modification of D.06-07-030, in order to create a common PCIA calculation workpaper template in the IOUs' ERRA Forecast proceedings. The Commission adopted this template in D.17-08-026.

¹⁵ The OIR named PG&E, SCE, SDG&E, all CCAs (see Appendix B of the OIR) and all ESPs (see Appendix C of the OIR) as respondents to this proceeding.

schedule for service of testimony and rebuttal testimony, the evidentiary hearings, and concurrent opening briefs and concurrent reply briefs.

On April 2, 2018 the following parties served testimony: SCE, PG&E and SDG&E (Joint Utilities), the Commission's Office of Ratepayer advocates (ORA), The Utility Reform Network (TURN), Utility Consumer's Action Network (UCAN), Protect Our Communities Foundation (POC), Coalition for Utility Employees (CUE), California Community Choice Association (CalCCA), Alliance for Retail Energy Markets and the Direct Access Customer Coalition (ARem/DACC), Commercial Energy, and Energy Users Forum (EUF). On April 23, 2018 the following parties served rebuttal testimony: the Joint IOUs, TURN, UCAN, CUE, CalCCA, ARem/DACC, Commercial Energy, Energy Producers and Users Coalition (EPUC) and California Large Energy Consumers Association (CLECA).

On April 24, 2018 the Joint Utilities filed and served a joint motion requesting oral argument. On July 19, 2018 a ruling granted the motion and scheduled Oral Argument for August 2, 2018.

Evidentiary hearings were conducted for five days from May 7 through May 11, 2018.

Pursuant to the direction of the assigned ALJ, on May 24, 2018 the Joint Utilities filed and served a motion for admission of additional evidence into the record, consisting of Exhibit IOU-5.¹⁶ That motion is hereby granted.

¹⁶ Exhibit IOU-5, "Response to Questions from Assigned Commissioner and Assigned Administrative Law Judge Ruling Confirming Scoping Memo Issues dated 11/22/2017."

Opening briefs were filed and served on June 1, 2018 by American Wind Energy Association (ACC), AReM/DACC, Brightline Defense Project (Brightline), CalCCA, Commercial Energy, CUE, CLECA, the City of San Diego, the California Manufacturers & Technology Association (CMTA), EPUC, the Independent Energy Producers Association (IEP), Los Angeles Community Choice Energy, Coachella Valley Association of Governments (CVAG) and the Western Riverside Council of Governments (WRCOG) (Joint CCAs), Joint IOUs, ORA, POC, the Regents of the University of California (UC, in its role as an Electric Service Provider), Shell Energy North America (US), L.P. (Shell Energy), Solana Energy Alliance (SEA), TURN, and UCAN.¹⁷

On June 6, 2018 the assigned ALJ directed parties to address the mechanics of implementing their proposals in their reply briefs.

Reply briefs were filed and served on June 15, 2018 by ACC, AReM/DACC, Brightline, CalCCA, Commercial Energy, CUE, CLECA, Joint IOUs, ORA, POC, UC, SEA, TURN, and UCAN.

On June 25, 2018, as directed by the ALJ, supplemental briefs were filed and served by AReM/DACC, CalCCA, Commercial Energy, and the Joint IOUs. The supplemental briefs were limited to addressing the implementation proposals made by other parties in their reply briefs.

¹⁷ LACCE has since been renamed the “Clean Power Alliance of Southern California.” CVAG has officially formed a separate joint powers agency known as “Desert Community Energy” that provides CCA services to its members and is administered by CVAG.

2. Issues Before the Commission

Pursuant to the September 25, 2017 Scoping Memo, the list below identifies the issues that the Commission shall resolve in this proceeding.

1. Does the current PCIA methodology prevent cost increases for bundled customers as a result of either (1) retail customers of an electrical corporation electing to receive service from other providers or (2) the implementation of a CCA program?
2. Does the current PCIA methodology prevent cost increases for CCA customers and direct access customers as a result of an allocation of costs that were not incurred on behalf of the departing load?
3. If the answer to question 1 or 2 is “no”, can the current PCIA methodology be revised to ensure that cost increases are prevented for bundled and departing load?
4. If not, what replacement methodology should the Commission adopt in order to meet the statutory requirement to ensure that bundled retail customers shall not experience any cost increases as a result of either (1) retail customers of an electrical corporation electing to receive service from other providers or (2) the implementation of a CCA program, and 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.
5. How should the Commission ensure access to necessary data and require transparency of calculations in order to enable interested parties to (1) review the current PCIA methodology and understand its results and (2) contribute to and understand the development of any possible replacement methodology?¹⁸

¹⁸ Revisions to confidentiality rules related to PCIA are the subject of a Petition for Modification of Decision 11-07-028, filed and served by the California Community

Footnote continued on next page

6. Should the Commission require and verify optimization of IOU portfolio management (e.g., contract extensions and contract renegotiation) in order to minimize above-market costs?
7. Should the Commission adopt alternatives to the PCIA framework, including but not limited to the following?
 - a. The Joint Utilities' Portfolio Allocation Methodology
 - b. Portfolio buy-out by CCA/ESP
 - c. Assignment of IOUs' contracts to CCA/ESP
 - d. Options for customers to prepay the PCIA on a one-time basis, to be relieved of the PCIA burden going forward.
8. Should the Commission require forecasting of the PCIA or an alternative cost allocation method for a specific future period?
9. Should the Commission "cap" the PCIA or an alternative cost allocation method?
10. Should the Commission adopt a sunset of the obligation to pay the PCIA or an alternative cost allocation method?
11. Additional considerations and statutory changes relevant to review, revision, and consideration of alternatives to the PCIA.

The Scoping Memo also identified an "overall goal" for this proceeding and, based on parties' comments on the initial Rulemaking, articulated a corresponding list of principles that would guide the proceeding. Parties supported their proposals by referencing the overall goal and the guiding principles.

Choice Association on June 13, 2017. The Petition seeks modification of the Commission's existing confidentiality rules to allow specified employees of CCAs access to certain information that. That access is barred by current rules.

Overall Goal of this Proceeding

The Commission shall ensure that bundled retail customers of an electrical corporation shall not experience any cost increases as a result of either (1) retail customers of an electrical corporation electing to receive service from other providers or (2) 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.

As explained in the Scoping Memo, the other guiding principles provided in the Rulemaking were revised and reorganized to reflect the statutorily required balance between bundled load and departing load¹⁹:

Final Guiding Principles

1. Any PCIA methodology adopted by the Commission to prevent cost increases for either bundled or departing load:
 - a. 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;
 - b. should have reasonably predictable outcomes that promote certainty and stability for all customers within a reasonable planning horizon;
 - c. should be flexible enough to maintain its accuracy and stability if the number of departing customers changes significantly, and to maintain its accuracy and stability if customers return to bundled-customer service;
 - d. should not create unreasonable obstacles for customers of non-IOU energy providers;

¹⁹ Scoping Memo at 13.

- e. should be consistent with California energy policy goals and mandates;
- f. should allow alternative providers to be responsible for power procurement activities on behalf of their customers, except as expressly required by law;
- g. should allow an alternative provider to elect to pay for its share of above-market costs in a manner that complements the CCA's particular procurement needs and goals;
- h. should only include legitimately unavoidable costs and account for the IOUs' responsibility to prudently manage their generation portfolio and take all reasonable steps to minimize above-market costs;
- i. should reflect the value of the benefits that departing customers impart to remaining bundled service customers;
- j. should accurately reflect and seek to preserve all short, medium, and long-term value of the resources procured by the utilities; and
- k. should respect the terms of existing power purchase agreements between power suppliers and IOUs.

We will return to these principals at the conclusion of this decision.

2.1. Proposals

In this section, we summarize what parties generally agree are the "complete" proposals before us in this proceeding, meaning those that at least some subset of the parties believe could be implemented in time to replace the current PCIA by January 1, 2019.

2.1.1. Joint Utilities: Green Allocation Methodology and Portfolio Monetization Mechanism

The Joint Utilities describe their proposed Green Allocation Methodology and Portfolio Monetization Mechanism (GAM/PMM) as "an allocation mechanism whereby the benefits, attributes, value, and costs of the resources in the Joint Utilities' generation portfolios follow the customers for whom they

were procured: if customers depart utility bundled service for a CCA or ESP, those benefits and costs follow the customers to their new LSE. If those customers subsequently return to utility bundled service or receive service from a new LSE, those benefits and costs follow them back to the utility or new LSE.”²⁰

Under GAM, the RPS-eligible and large hydroelectric resources’ benefits and costs are allocated to all customers in the following way: the Joint Utilities continue to manage the resources and make them available to the California Independent System Operator (CAISO) for dispatch. The resulting market revenues (for energy, A/S, and any other revenues) are then assigned pro rata to all benefitting customers as an offset to the costs of those resources. Additionally, the RA and REC attributes of those resources are allocated pro rata to the LSEs serving departing load customers.

Under PMM, the RA for other portfolio resources is allocated pro rata, the departing load customers’ share of which would be monetized in regularly-occurring auctions. The market revenues for energy, A/S, any other revenues (and RA monetization for departing load customers) are then assigned pro rata to all benefitting customers as an offset to the costs of those resources. The net costs of PMM resources are assigned pro rata to all benefitting customers.

The Joint Utilities assert that GAM/PMM is the only proposal in this proceeding that “eliminates illegal cost shifts, equitably allocates the costs and benefits of the utilities’ historical procurement to customers for whom they were procured, preserves the value of those resources, supports the State’s public policy goals, maintains Commission oversight over those resources, and is

²⁰ Joint Utilities opening brief at 43.

immediately implementable and scalable for all potential levels of departing (and returning) load.”²¹

2.1.2. AReM/DACC

AReM/DACC proposes that (1) the existing Energy "Brown Power" Index be retained; (2) a revised RPS adder be calculated using the average of Platt's Megawatt Daily (or a similar source) published PCC 1 REC indices; and (3) a revised capacity adder should be developed that is “tied to a Commission determination as to whether new capacity resources are needed within the next three years”:²²

- If so, then the cost of new entry (CONE) for a new combustion turbine (CT) could be used. This value would be from the California Energy Commission’s most recent Cost of New Generation Report.
- If the need for new capacity is projected to be four years or more in the future, then the going forward cost of a new CT should be used (*e.g.*, the status quo), or some other form of discounted CONE.

2.1.3. CalCCA

CalCCA prefaces its proposal by suggesting that “the magnitude and complexity of the coming changes in the procurement market require a comprehensive solution consistent with governing statutes.”²³ CalCCA’s fundamental point is that long-term resources should be valued using long-term valuation measures:

²¹ *Id.* at 42-43.

²² AReM/DACC opening brief at 24, citing D.11-12-018 at 30.

²³ CalCCA opening brief at 10.

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 the 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.²⁴

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.”²⁵ Nevertheless, CalCCA acknowledges that a solution is required to address the growing mismatch between bundled utility portfolio resources and bundled load, as CCA load grows.

For these reasons, 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.

In the near term, CalCCA proposes to mitigate what it sees as 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).

In order to correct the value side of the equation, CalCCA recommends:

- Replacing the current short-term capacity value with a Commission-adopted long-term resource value;

²⁴ CalCCA opening brief at 42, citing Cal. Pub. Util. Code §366.2(f)(2) and §366.2(g).

²⁵ *Ibid.*

- Adding a component to account for the value of GHG-free resources not currently reflected in the benchmark;
- Adding a component to account for the value of ancillary services not currently reflected in the benchmark; and
- Making a minor modification of the Green Adder to remove the outdated DOE value component.

In order to correct the cost side of the equation, CalCCA proposes to remove Legacy UOG costs from CCA cost responsibility.

CalCCA envisions that its Corrected Methodology would remain in place until its proposed Staggered Portfolio Auction (SPA) can be implemented. The SPA would replace the value measures for GHG-free and RPS resources, and the Corrected Methodology would remain in place for fossil resources until they are no longer included in the PCIA-eligible portfolio.

CalCCA explains that 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 they need to meet their customers' needs. In this way, according to CalCCA, the SPA would ensure voluntary redistribution of utility portfolio resources and generate more reasonably representative market prices to draw a boundary between uneconomic and economic portfolio costs.

CalCCA suggests that adoption of its proposal would allow the Commission to meet its statutory obligations to preserve CCAs' rights to autonomy in building their portfolios.²⁶

²⁶ CalCCA opening brief at 9.

As we will discuss later in this decision, CalCCA joins other parties in recommending that while the Commission-adopted 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.

2.1.4. Commercial Energy

Commercial echoes CalCCA's point that the valuation of the excess resources in the IOU portfolios is a critical component of the PCIA calculation, but recommends replacing the Commission's administratively-determined benchmarks with other means of valuing the excess resources in the portfolios. Commercial strongly supports the development of real market prices for the resources in the IOU portfolios, but also identifies the Commission's current challenge: "to obtain market prices, there must be a functioning market with a critical mass of participants and price disclosure for market participants."

Commercial states that one of the primary goals of its "Voluntary Allocation & Auction Clearinghouse" (VAAC) proposal is achieving a market with the characteristics it describes. The VAAC is based on an existing mechanism used on the PG&E natural gas system to allocate stranded core transmission and storage assets to Core Transport Agents:

That mechanism was created because the CTAs gained more than 10 percent market share and a cost allocation mechanism had to be implemented to ensure bundled-customer indifference. The PG&E/CTA mechanism involves a voluntary triannual allocation of the assets, and then an auction open to all bidders of assets not accepted in the allocation.²⁷

²⁷ Commercial Energy opening brief at 4.

Applying this model to the PCIA context, Commercial Energy proposes the following steps:

1. The first step is a voluntary allocation to LSEs of all PCIA-eligible IOU resources:

The resources would be aggregated into pools by technology or attribute type, which means that the actual performance and price data for the pools can be safely shared with the market-participant LSEs so that they have some degree of price discovery regarding the assets they are asked to accept. An LSE that accepts an allocation will pay the full contract cost for the asset, thereby removing those costs from the balance of the LSE's PCIA cost responsibility.

The goal is to encourage LSEs to accept these allocations by allowing them to also have the attributes, such as Resource Adequacy and Renewable Energy Credits for the associated resources, while also spreading the risk associated with hourly generation and dispatch imbalances over multiple assets within a single pool.

2. The second step in the VAAC process is a voluntary auction of the remaining resources:

All market participants could bid on the resources and the weighted average of the winning bids will fix the market price for the resource pools, and at the same time fix the remaining PCIA cost responsibility for the resources.

Following the auction, the IOU bids the resource into the CAISO markets in the same manner it does today, and the CAISO clears the price when the resource is dispatched. To ensure the winning bidder receives the price it originally bid, each winning LSE settles with the IOU based on the difference between the CAISO clearing price and the LSE's bid price. If the CAISO price is higher, the IOU pays the difference to the LSE; if the CAISO price is lower, the LSE pays the IOU the difference between the winning bid and the CAISO price. This preserves the result of the auction and gives price

certainty to the LSE and also fixes the PCIA cost for the resource.

3. The third step in the VAAC process requires that any remaining PCIA-eligible resources or costs not offset by revenues from the allocation or auction will be recovered in a residual PCIA charge much like the one that is calculated as the last step in the Joint Utilities' proposed Portfolio Monetization Mechanism, which allocates eligible above-market costs to each customer vintage.

Commercial puts its proposals in perspective by suggesting that “the Commission is in a unique position to consider adopting a combination of reforms to the PCIA process ... that will reform the current PCIA mechanism with real market prices to value the excess above-market resources, while at the same time creating a viable market that encourages LSEs to participate and accept or bid for excess IOU resources.”²⁸ Commercial contends that “this initial step is necessary to provide regulatory certainty about PCIA cost responsibility, and [o]nce that is accomplished, the LSEs and IOUs will be empowered to consider further steps, which will require more time, to reduce the cost of excess portfolio assets (securitization), or facilitate actual forward sales or assignments of all the energy and attributes associated with particular contracts or facilities.”²⁹

2.1.5. TURN

TURN recommends that the Commission adopt changes to the computation of the PCIA this year for implementation in 2019 PCIA rates so as to quickly move the PCIA methodology closer to the required “indifference”

²⁸ *Id.* at 5.

²⁹ *Ibid.*

standard, while taking other steps toward longer-term reforms (we discuss the latter proposals below).³⁰

TURN's PCIA proposal is based on the principal that in order to preserve indifference between bundled and unbundled customers, the computation of charges to be levied pursuant to the PCIA must be based on the actual "net costs" of the IOUs' relevant resources. TURN recommends that the market benefits provided by IOU resources should be estimated, as much as possible, based on the actual revenues such resources earn in relevant markets. For the output and attributes of IOU resources for which there is not a transparent market price, the Commission should develop measures that reflect as best as possible the actual prices that face entities seeking to buy or sell such output or attributes. TURN acknowledges "the relative lack of such price data for RA capacity and renewable power" but recommends that the Commission attempt to estimate these market prices for the forecast PCIA year as best as possible.³¹

For resource adequacy, "RA prices could be based on actual reported purchase and sales prices of IOU, CCA, and ESP transactions made during the prior year for deliveries in the forecast year."³² TURN explains that such a compilation of data would be similar to the data ED now produces in its RA reports, but should include more data sources subject to Commission jurisdiction and be produced on a basis timely enough to support the computation of PCIA charges.³³

³⁰ Exhibit TURN-2 at 2.

³¹ Exhibit TURN-1 at 9.

³² *Ibid.*

³³ *Id.*, footnote 22.

TURN recommends estimating the value of renewable power using the prices of purchases and sales of renewable energy made during the year prior to the forecast year, for delivery in that year, “both as bought and sold by the IOUs, CCAs and ESPs.” TURN recommends that the Commission should establish new transaction reporting requirements for CCAs and ESPs in order to calculate an accurate renewable component of the MPB.³⁴

TURN also notes that in the past, “IOUs acquired many long-term resources pursuant to Commission direction that showed little or no concern for the monthly shape of IOUs’ RA capacity needs” and

as a result, the IOUs have substantial “long” positions of System RA in non-peak months. Given the lower System RA requirements of such months, the IOUs may not be able to sell such capacity at any price. This impact of such possibly unsellable RA capacity surplus in non-peak months should also be factored into the Commission's estimates of RA prices, possibly by assigning a zero or *de minimis* price to unsold capacity in forecasting capacity value in the MPB.³⁵

In addition to the improved forecasting described above, TURN also recommends that a “true-up” mechanism should be implemented such that total PCIA collections are ultimately based on the actual net costs of the IOUs' relevant resources. Finally, TURN recommends that the Commission limit year-to-year increases in PCIA charges by imposing a limit or “cap” on the amount that PCIA charges can escalate from one year to the next.³⁶ TURN makes this recommendation based on its observation that “current, annually-fluctuating PCIA charges complicate individual

³⁴ Exhibit TURN-1 at 9.

³⁵ TURN opening brief at 15, citing Exhibit TURN-1 at 8-10.

³⁶ Exhibit TURN-1 at 11.

Retail Sellers planning efforts, creating cost uncertainty that may limit their ability to plan effectively, and, in particular, to pursue their clean resource development objectives.”³⁷

3. Framework for Preparing this Decision

This decision is generally organized to follow the sequence of topics in the common briefing outline developed by parties following hearings. The contested issues, the testimony and other evidence, and parties’ briefs are voluminous; for that reason, we begin each section with our determination on the relevant issues, followed by an overview of the issues and a point-by-point discussion of parties’ positions that explains how we reached our decision on each issue. We focus our discussion on the major points of contention and do not summarize every nuance of each party’s positions.

Our overall decision-making criteria are the Scoping Memo’s guiding principles as they relate to the statutory mandates that frame the issues within the scope of this proceeding. We discuss the statutory framework below, including how those mandates encompass not only the Legislature’s direct guidance regarding cost shifting in the context of departing load, but also a number of additional, broader mandates regarding energy procurement in California.

3.1. Statutory Framework

As noted in the background presented above, the Commission’s determinations regarding the PCIA are governed by an intricate statutory framework. Parties’ briefs in this proceeding revealed conflicting understandings of this statutory framework, so we undertake a brief review here

³⁷ *Ibid.*

in order to establish the necessary context for the findings and conclusions we reach in this decision. CalCCA provides a summary of the statutory framework regarding CCAs in its opening and reply briefs. We summarize and add to that analysis here.

CalCCA begins its analysis by urging the Commission not to focus the design of any solution to the issues in this proceeding on protecting bundled customers. Instead, CalCCA contends that “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.”³⁸ We do not disagree, but we note that the record of this proceeding suggests an undercurrent of tension between the utility respondents to the rulemaking and the parties representing the CCAs. For this reason, we find it worthwhile to begin with a review of the Legislature’s directives regarding how this Commission, and the electric utilities under our jurisdiction, are obligated to support CCAs.

This history begins in 2002 when the Legislature enacted AB 117, which provided that “Customers shall be entitled to aggregate their electric loads as members of their local community with community choice aggregators.”³⁹ Subsequent sections of AB 117 established the ground rules for the formation of CCAs and their attendant responsibilities and obligations. We note that the term “entitled” is used here in its positive sense: speakers at the public comment sessions of our own public voting meetings convey the extent to which, as

³⁸ CalCCA opening brief at 3, emphasis in the original.

³⁹ Public Utilities Code section 366.2 (a)(1), emphasis added.

residents of communities with operating CCAs, or that are considering formation of a CCA, they value the feeling of being in control of their energy choices by virtue of this “entitlement.” We acknowledge this sentiment and the related statutory directives at the outset of this decision.

CalCCA goes on to suggest that “the Legislature envisioned CCAs as partners with the utilities and state agencies in driving energy efficiency and conservation, increasing reliance on renewable resources and ensuring grid reliability.”⁴⁰ CalCCA further contends that “CCAs play a 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.”⁴¹ Again, we acknowledge that the benefits described by CalCCA may be realized through the actions of CCAs.

In CalCCA’s view “the Legislature has tasked the Commission with ensuring the success of its vision”⁴² and in realizing that vision, the Commission must do the following (we have replaced CalCCA’s paraphrasing with statutory language so as to provide an objective summary):

- Pursuant to §366.2(c)(9)-(11), enforce the requirement that the electric utilities “shall cooperate fully” with any CCAs that investigate, pursue, or implement CCA programs;
- Pursuant to Senate Bill 790 establish a code of conduct, associated rules, and enforcement procedures, applicable to electric utilities “in order to facilitate the consideration,

⁴⁰ CalCCA opening brief at 3.

⁴¹ *Id.* at 3-4.

⁴² *Id.* at 4.

- development, and implementation of CCA programs, to foster fair competition, and to protect against cross-subsidization by ratepayers;”
- Pursuant to §366.2(c)(5)-(8), certify CCA implementation plans;
 - Pursuant to §366.2(a)(4) ensure that the implementation of a CCA program “shall not result in a shifting of costs between the customers of the CCA and the bundled service customers of the electric utility;⁴³
 - Adhere to the requirement of §366.2(a)(4) that a CCA “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;” and
 - Pursuant to §380 “establish resource adequacy requirements for all load-serving entities” in a manner consistent with the CCA-specific parts of that Section:
 - §380 (a)(5), “maximize the ability of community choice aggregators to determine the generation resources used to serve their customers;”
 - §380 (g), “exclude any amounts authorized to be recovered pursuant to Section 366.2 when authorizing the amount of costs to be recovered from customers of a community choice aggregator or from customers that purchase electricity through a direct transaction pursuant to this subdivision.”
 - §380 (h), “determine and authorize the most efficient and equitable means for achieving, among other things,

⁴³ CalCCA also cites the provisions of Section 366.3: “Bundled retail customers of an electrical corporation shall not experience any cost increase as a result of the implementation of a CCA 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.”

- (4) Ensuring that the cost of generating capacity and demand response is allocated equitably; and
- (5) Ensuring that community choice aggregators can determine the generation resources used to serve their customers.

- Pursuant to §399.11 *et seq.*, ensure CCA compliance with RPS requirements.

CalCCA next relates these statutory mandates to our tasks within this proceeding. First, CalCCA notes that “this rulemaking was instituted primarily to implement the Commission's responsibility to prevent cost shifts between bundled and departing load customers;”⁴⁴ indeed, as will be discussed below the Scoping Memo declares that preventing cost shifts is the “Overall Goal of this Proceeding.”

CalCCA also calls attention to the precise wording of AB 117, as now codified in sections 366.2 (f) and (g):

- (f) A retail end-use customer purchasing electricity from a community choice aggregator pursuant to this section shall reimburse the electrical corporation that previously served the customer for all of the following:
 - (1) The electrical corporation's unrecovered past undercollections for electricity purchases, including any financing costs, attributable to that customer, that the commission lawfully determines may be recovered in rates.
 - (2) Any additional costs of the electrical corporation recoverable in commission-approved rates, equal to the share of the electrical corporation's estimated net unavoidable electricity purchase contract costs attributable to the customer, as determined by the

⁴⁴ *Ibid.*

commission, for the period commencing with the customer's purchases of electricity from the community choice aggregator, through the expiration of all then existing electricity purchase contracts entered into by the electrical corporation.

- (g) Estimated net unavoidable electricity costs paid by the customers of a community choice aggregator shall be reduced by the value of any benefits that remain with bundled service customers, unless the customers of the community choice aggregator are allocated a fair and equitable share of those benefits.

CalCCA bases its positions in this proceeding on these code sections, and we will return to them later in this decision. For now we continue with our review of the statutory framework and its relationship to our tasks within this proceeding.

CalCCA's second point regarding the Commission's statutory obligations in the context of this proceeding is that "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."⁴⁵ CalCCA cites the codification of this obligation in Section 366.2(a)(5):

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

The Commission's obligation in this respect is acknowledged in one of the guiding principles adopted in the Scoping Memo: any methodology adopted by

⁴⁵ *Id.* at 8.

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 expressly required by law.”⁴⁶

CalCCA’s third point regarding the Commission’s statutory obligations in the context of this proceeding is that, in order to “fulfill the Legislature’s vision for CCAs and the Commission’s own commitments to preserve fair competition among LSEs [load serving entities], the Commission must prevent the use of utility dominance to undermine CCA development or operation.”⁴⁷

CalCCA cites one of the legislative findings and declarations at the beginning of SB 790, adopted by the Legislature in 2011.⁴⁸ Those findings and declarations express the Legislature’s position regarding the relationship between CCAs and the electric utilities subject to the Commission’s jurisdiction, including: it is the policy of the state “to provide for the consideration, formation, and implementation of CCA programs”; electric utilities have inherent market power, the exercise of which “is a deterrent to the consideration, development, and implementation of community choice aggregation programs;” and, “California has a substantial governmental interest in ensuring that

⁴⁶ Scoping Memo at 14, Guiding Principle 1.f.

⁴⁷ CalCCA opening brief at 9, citing SB 790 at §2(h).

⁴⁸ Stats. 2011, Ch. 599. We take special note that the Legislature entitled SB 790 the “Charles McGlashan Community Choice Aggregation Act.” The Legislature declared that “in naming this act, it is the intent of the Legislature to honor” the late Marin County Supervisor Charles McGlashan “for championing the right of local governments to aggregate their electricity loads for the purpose of procuring and generating more renewable energy, expanding consumer choice, and greatly accelerating regional efforts to address global climate change.” The Legislature further noted that Supervisor McGlashan founded the Marin Energy Authority, which launched California’s first Community Choice Aggregation program, Marin Clean Energy.

conduct by electrical corporations does not threaten the consideration, development, and implementation of community choice aggregation programs.”⁴⁹ These findings and declarations form the basis for the Legislature’s conclusion in section 2(h) of the list, and its mandate to the Commission:

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.

SB 790 added Section 707 to the Public Utilities Code, directing the Commission to institute a rulemaking proceeding to consider and adopt a code of conduct, associated rules, and enforcement procedures to govern the conduct of regulated electrical corporations relative to the consideration, formation, and implementation of CCAs. The Commission responded by opening Rulemaking 12-02-009 and subsequently adopting D.12-12-036, which created the CCA Code of Conduct and Expedited Complaint Procedure mandated by SB 790.

CalCCA’s fourth and final point regarding the Commission’s statutory obligations in the context of this proceeding is simply to note the Commission’s fundamental obligation in all ratesetting proceedings: the Commission must ensure just and reasonable rates. CalCCA asserts that “the Public Utilities Code permits the Commission to allocate to CCA departing load only the ‘unavoidable’ costs of the utilities’ portfolios, excluding costs that are avoidable.”⁵⁰ By juxtaposing § 451 and section § 366.2(f)(2) CalCCA asserts that

⁴⁹ See SB 790, Section 2.

⁵⁰ CalCCA opening brief at 10, citing § 366.2(f)(2).

“consequently, the Commission must ensure that the utilities minimize portfolio costs for all customers and exclude avoidable costs from recovery through the PCIA.”⁵¹

3.2. Evidentiary Standards, the Burden of Proof, and the Burden of Production

Finally, we also remind parties of the Commission’s general standards regarding burden and standard of proof, and discuss how those standards are applied in this decision.

Beginning generally, pursuant to Pub. Util. Code § 451 all rates and charges collected by a public utility must be “just and reasonable” and a public utility may not change any rate “except upon a showing before the commission and a finding by the commission that the new rate is justified.”⁵² The Commission requires that utility applicants demonstrate with admissible evidence that the costs which they seek to include in revenue requirement are just and reasonable. With this burden of proof placed on the utility applicant, the Commission has held that the standard of proof that must be met is that of a preponderance of evidence. Preponderance of the evidence is usually defined “in terms of probability of truth, e.g., ‘such evidence as, when weighed with that opposed to it, has more convincing force and the greater probability of truth’.”⁵³ In short, in typical ratesetting proceedings the applicant must present more

⁵¹ *Ibid.*

⁵² Pub. Util. Code § 454.

⁵³ *Decision Granting a Certificate of Public Convenience and Necessity for the Sunrise Powerlink Transmission Project* [D.08-12-058] at 19 (citing Witkin, *Calif. Evidence*, 4th Edition, Vol. 1 at 184).

evidence that supports the requested result than would support an alternative outcome.

Still speaking in general terms, the counterpoint to the applicant's burden of proof is the burden the Commission places on intervenors in proceedings, the burden of producing evidence:

[W]here other parties propose a result different from that asserted by the utility, they have the burden of going forward to produce evidence, distinct from the ultimate burden of proof. The burden of going forward to produce evidence relates to raising a reasonable doubt as to the utility's position and presenting evidence explaining the counterpoint position. Where this counterpoint causes the Commission to entertain a reasonable doubt regarding the utility's position, the utility has not met its ultimate burden of proof.⁵⁴

Turning to this rulemaking proceeding, it differs from a typical single-utility ratemaking proceeding. Here, all parties have equal standing where their proposals are concerned: they must show by a preponderance of the evidence that the Commission should adopt their proposal, rather than an alternative. Similarly, each party also bears the burden of production for those parts of their showing that ask the Commission to disregard a competing proposal: "the burden of going forward to produce evidence ... raising a reasonable doubt as to the utility's position and presenting evidence explaining the counterpoint position."

We have analyzed the record in this proceeding within these parameters.

⁵⁴ D.87-12-067, 27 CPUC2d 1, 22.

4. **Cost Shifts Under the Current Methodology**

This section of this decision addresses the first two issues listed in the Scoping Memo:

1. Does the current PCIA methodology prevent cost increases for bundled customers as a result of either (1) retail customers of an electrical corporation electing to receive service from other providers or (2) the implementation of a CCA program?
2. Does the current PCIA methodology prevent cost increases for CCA customers and direct access customers as a result of an allocation of costs that were not incurred on behalf of the departing load?

While party positions differ with respect to the direction and underlying nature of cost shifts between bundled customers and departing load customers, every party that submitted testimony and/or briefs in this proceeding asserts that the current PCIA methodology does in fact result in impermissible cost shifts.

A number of parties provided analyses and explanations for the shortfalls in the current methodology. Rather than summarizing many parties' positions in a repetitive manner, we rely here on testimony submitted by TURN for a brief but comprehensive overview.

TURN first provides a conceptual description of the PCIA calculation, which we represent in the graphic below:

<i>Formula:</i>	<i>Definition of terms:</i>
GROSS COSTS	Equal to: IOUs' costs of owning or contracting for certain resources subject to the PCIA
Minus: MARKET BENEFITS	Equal to: [forecast IOU revenues] + [forecast IOU costs avoided thru ownership of resources]
Equals: NET COSTS to be recovered by the PCIA	

TURN’s representation is expressed in the jargon of this proceeding as:

$$\boxed{\text{Total Portfolio Costs}} - \boxed{\text{Market Value of Portfolio}} = \boxed{\text{Indifference Amount}}$$

At public workshops early in this proceeding, the terms in the equation above were defined as follows:

Total Portfolio Costs = the sum of:	Market Value of Portfolio = the sum of:
Base Generation Capital Revenue Requirement	“Brown” Energy x Brown MPB
	where the Brown MPB = Weighted Average of Platt’s On and Off Peak Trading Prices (NP-15/SP-15 Specific)
UOG Fuel and Direct GHG Costs	“Green” Energy x Green MPB
	where the Green MPB = Weighted Average Price of CA IOUs’ Newly-Delivering Renewable Contracts and DOE Renewable Programs
Qualifying Facility and CHP Contracts	Net Qualifying Capacity x Capacity MPB
	where the Capacity MPB = Going Forward Cost of a Combustion Turbine
Bilateral and RFO Contracts	
Refunds and Adjustments	

Source: Exhibit IOU-5, Appendix A, PCIA Rulemaking Workshop 1b Presentation December 5, 2017, slide 18.

Like other parties, TURN faults the current PCIA methodology because it estimates the potential market benefits of utility-controlled resources based on measures that do not reflect the actual market value of such resources, or “perhaps more importantly, such resources’ actual cash benefits to the IOUs,”

such as revenues from recorded sales of--or costs that can be avoided because of--such resources' output or attributes.⁵⁵

TURN contends that (1) "to achieve true indifference, the PCIA mechanism should ultimately reflect the IOUs' actual net costs of owning and contracting for relevant resources, that is, their actual gross costs less their realized market benefits; and (2) the "Market Price Benchmark" (MPB) that is used to estimate the benefits the IOUs realize from their owned and contracted resources "do not, in fact, reflect market prices (and thus the costs the IOUs can earn or avoid due to their control of such assets)."⁵⁶

We review each of the three components that make up the MPB below:

4.1. "Brown Power" Market Price Benchmark

Parties offered no real objection to the current methodology for calculating what has come to be called the "brown power" market price benchmark.

CLECA contends that "record evidence demonstrates that the brown energy benchmark is performing adequately," citing TURN's rebuttal testimony: "In general, parties seemed to take little issue with the use of wholesale market prices of energy to estimate the value of energy in the current MPB."⁵⁷ CLECA recommends that no revision to this benchmark is necessary. AReM/DACC's testimony provided a comparison of the brown power energy component of the MPB with average CAISO day-ahead prices, and demonstrated that "except for 2015, the two MPB and CAISO averages have been within approximately 15% of each other." AReM/DACC concludes that "the brown power index continues to

⁵⁵ Exhibit TURN-1 at 5.

⁵⁶ *Ibid.*

⁵⁷ CLECA opening brief at 9, citing Exhibit TURN-2 at 4.

be reasonable and that market forwards, taken as close to the end of the year as practical, should continue to be used.”⁵⁸

POC contends that the brown power MPB fails to capture the full value of portfolio resources:

the energy benchmark uses market indices for a one-year strip of on-peak and off-peak power prices for the coming calendar year. The benchmark relies on the flawed assumption that short-term sales capture the full value of long-term brown power contracts. This mismatch fails to credit departing load for the “inherent hedge and option value” in long-term contracts, such as the ability of the contract owner to use the asset flexibly in response to price fluctuations and to hedge against risk exposure.⁵⁹

We do not dismiss the analysis and contentions of POC and other parties regarding the question of whether the current benchmarks completely capture the long-term value of portfolio resources. At the same time, these parties have had difficulty proving, with evidence, that this is the case. We are left to base our

⁵⁸ AReM/DACC opening brief at 21-22, citing and reproducing Figure 1 in Exhibit AD-01.

⁵⁹ POC opening brief at 6, citing the following:

- D.07-01-030 at 13; Exhibit AD-01 at 9;
- RT at 1066 (TURN, Woodruff) (testifying that it "might be" possible that "there is value in a long-term brown power contract . . . that couldn't be realized through . . . short-term sale into the Cal ISO market"); *id.* at 1068 (TURN, Woodruff) (testifying that it may be "appropriate to match the curve that you're using to gauge value of an attribute closer to the term of the contract under which it's procured" if longer-term forward curves could be located);
- Exhibit UCAN-01 at 9; RT at 899- 900 (CalCCA, Hoekstra);
- RT at 1094 (UCAN, Woychick); and
- RT at 900 (CalCCA, Hoekstra).

decision on what we are able to observe and verify. On that basis, we find that AReM/DACC's analysis has established that the brown power index continues to be reasonable. Therefore, we leave this particular MPB unchanged in this decision.

4.2. RA Capacity Value

TURN joins other parties in faulting the Commission's currently-adopted method for estimating the RA capacity value. TURN asserts that this method results in an estimate that "has very little relationship to the actual market prices at which all LSEs buy and sell RA capacity."⁶⁰ In TURN's view, the current estimated value is too high, and "thus overstates the market benefits of IOU resources' capacity, leading to an understatement of the charges that should be recovered in the PCIA."⁶¹

In the Commission's current PCIA methodology the RA capacity value used to estimate market benefits of utility resources is defined as the "going forward cost (sum of insurance, ad valorem and fixed operations and maintenance costs) of a combustion turbine as determined per the most recent California Energy Commission (CEC) Comparative Costs of California Central Station Electricity Generation Report for a small simple cycle merchant plant."⁶² TURN speaks for most parties in finding that this estimate has very little relationship to the actual market prices at which all LSEs buy and sell RA capacity."⁶³ TURN cites the following examples:

⁶⁰ *Id.* at 6.

⁶¹ *Ibid.*

⁶² *Ibid.*, citing Commission Resolution E-4475, Exhibit A at 2.

⁶³ *Ibid.*

- The most recently-adopted capacity value for the MPB is \$58.27/kW-year, which yields an average cost of \$4.86/kW-month.
- This value differs from the 2016 Resource Adequacy Report prepared by the Commission's Energy Division:⁶⁴
 - the weighted average price of "System RA" contracts for the years 2016 to 2020 is estimated to be \$2.44/kW-month; 85 percent of all such MW were priced at or below \$3.00/kW-month.
 - For "Local RA" the weighted average price was \$3.20/kW-month and 85 percent of all such MW were priced at or below \$4.19/kW-month.
- According to TURN, the Energy Division provided additional information on local area capacity prices in a workshop in the current RA docket that suggested 85 percent of local RA capacity under contract for the years 2016 to 2020 was priced at or below \$2.50 to \$4.34/kW-month.⁶⁵

Based on these values, TURN concludes that "use of the capacity value of \$58.27/kW-year (\$4.86/kW-month) thus overstates the market benefits of IOU resources' capacity, leading to an understatement of the charges that should be recovered in the PCIA."⁶⁶

⁶⁴ *Ibid.*, citing the Energy Division's "2016 Resource Adequacy Report" at 23.

⁶⁵ *Ibid.*, and Attachment C to Exhibit TURN-1.

⁶⁶ *Id.* at 7.

4.3. Renewable Resources

TURN also finds the data used to estimate the market benefits of the IOU renewable resources to be inadequate, because they “do not reflect the actual benefits an IOU would earn selling such resources in the market.”⁶⁷

In the Commission’s current PCIA methodology the market value of the IOUs’ renewable generation is estimated by adding two components to the Commission’s originally-adopted “brown power index” value: (1) the IOUs’ renewable costs (“URGreen”) and (2) a “renewable premium” (DOEadder).⁶⁸ The total market value is equal to the sum of 68 percent of the URGreen value plus 32 percent of the DOEadder value plus the value of the “brown power index”. As TURN clarifies, “the DOEadder is used as part of an estimate [of] the total value of renewable power, and is not used as a stand-alone “renewable premium” or Renewable Energy Credit (REC) price.”⁶⁹

TURN faults this aspect of the current methodology for two reasons. First, TURN asserts that “URGreen” is a measure of a subset of the IOUs’ “embedded costs” of renewable resources (i.e., the average of the costs of renewable resources expected to start service over two specific years: the year before the forecast and the year of the forecast), and not of the market value of such renewable resources: “that is, regardless of the revenues an IOU could earn selling renewable power in a given year, the MPB presumes that such sales would be at the IOU’s embedded costs.”⁷⁰ Second, TURN notes that the U.S.

⁶⁷ *Ibid.*

⁶⁸ *Ibid.*, citing Commission Resolution E-4475, Exhibit A.

⁶⁹ *Ibid.*

⁷⁰ *Id.* at 8, emphasis added.

Department of Energy (DOE) has apparently stopped publishing the index used to calculate the DOEadder but in any case, “the assumption that the value of renewable energy can be estimated as the cost of ‘brown power’ plus an adder to reflect such power's renewable attributes may be outdated. It is not at all clear that renewable power will necessarily trade at a positive premium to brown power.”⁷¹

As we noted above, not all parties agree with the quantitative conclusions reached by TURN regarding which customer groups are harmed or benefitted by the inaccuracies of the Commission’s current method, nor with TURN’s recommendations to the Commission regarding solutions. Our purpose in presenting TURN’s analysis is only to provide a brief, clear explanation of the problems inherent in the current method.

Based on TURN’s explanations as well as those provided by other parties, we find that the current method cannot prevent cost shifts between customers, and is therefore in conflict with Sections 365.2 and 366.3 to the Public Utilities Code.

4.4. The Costs at Issue in this Proceeding

Before turning to parties’ recommended solutions we review additional information from the proceeding record regarding the source, composition and duration of the costs in question.

The Scoping Memo stated that the underlying nature of the cost responsibility of departing load customers cannot be fully understood--and accepted--by those customers unless this proceeding analyzed the source of those costs, and the reasons the IOUs incurred them when they did. The Scoping

⁷¹ *Ibid.*

Memo also drew a distinction between “revisiting” prior Commission determinations and “analyzing” the outcomes of those determinations, finding consensus among parties that a detailed analysis of underlying costs, supported by an accessible factual record, was required in this proceeding.⁷² A second ruling of the assigned ALJ and assigned Commissioner confirmed the intended analysis, stating

customers responsible for paying the PCIA should reasonably expect that by the time this proceeding is concluded, the Commission has thoroughly reviewed why their PCIA rate is at the level it is today and how it has changed over time, which IOU resources have contributed to those costs, and when that responsibility will end.⁷³

This section of the decision provides answers to these four questions, albeit at a more general level of detail than is available in the detailed evidentiary record available to us, and to parties. By providing this information, we also establish the necessary background and context for our determinations in this decision regarding the steps that should be taken immediately and in the longer term in order to ensure that the conditions facing us today do not recur.

At the conclusion of hearings, the Joint Utilities agreed to prepare an exhibit using data provided earlier to all parties, intended to provide quantitative responses to the four questions framed in the Scoping Memo.⁷⁴ We summarize information from those responses below. We also acknowledge that not all parties agree with the responses provided by the Joint Utilities.

⁷² September 25, 2017 Scoping Memo and Ruling of Assigned Commissioner at 19-20.

⁷³ November 22, 2017 Ruling Confirming Scoping Memo Issues at 10.

⁷⁴ Exhibit IOU-5.

Again, our purpose here is to establish context showing the magnitude of the challenges we are addressing in this decision.⁷⁵

1. Why is the PCIA rate at the level it is today?

The Joint Utilities provide the following response to this question:

The Joint Utilities' generation portfolios have been built over time, at the direction and oversight of the Commission, to ensure reliability, provide supply diversity, and achieve environmental and other state policy objectives on behalf of the Joint Utilities' then-existing bundled service customers. Those generation portfolios include utility-owned generation and third-party purchase power contracts with the single largest category of costs being fixed-price renewable resource contracts.

Meanwhile, the market value of those portfolios has steadily declined over time as the market price of renewable energy has decreased.

The Joint Utilities also cite their written testimony to add to this explanation:

“[t]his early procurement of renewable energy generation resources, which ultimately contributed to the steady decrease in market prices that are accessible to CCAs and other LSEs today, constitutes the majority of the above-market portfolio costs that have contributed to recent increases in the PCIA...Of course, even though the ‘market value’ of these Legacy resources has declined over time, the Joint Utilities’ payment obligations to the generator counterparties have remained fixed at the original contract prices.”⁷⁶

2. How has the PCIA rate changed over time?

The Joint Utilities provide the following response to this question:

⁷⁵ The indented text below is excerpted from the first four pages of Exhibit IOU-5.

⁷⁶ Exhibit IOU-1 at page 1-10 to page 1-11.

As demonstrated in Figure 2-25 on Page 2-26 of Exhibit IOU-1, since 2012 changes in the PCIA have largely been driven by changes in the market price benchmark--specifically, changes to the Renewable Energy Credit (REC) benchmark (which makes up a portion of the Market Price Benchmark), as well as changes in the underlying compositions and costs of the Joint Utilities' portfolios as signed renewable resources have come online. For reference, the 2012-18 benchmarks for RECs, Resource Adequacy, and Energy are listed in the table below:

	2012	2013	2014	2015	2016	2017	2018
REC Benchmark (\$/MWh)	\$63.94	\$63.78	\$69.76	\$61.15	\$47.75	\$33.54	\$27.70
RA Benchmark (\$/kW-Year)	\$50.17	\$50.17	\$50.17	\$50.17	\$58.27	\$58.27	\$58.27
NP-15 Energy Benchmark (\$/MWh)	\$35.23	\$41.27	\$41.39	\$43.73	\$34.87	\$37.33	\$33.77

3. Which IOU resources contributed to the PCIA costs?

The Joint Utilities provide a somewhat unenthusiastic response to this question, simply citing Appendix F of Exhibit IOU-1 "for a complete list of the Joint Utilities' generation resources that are subject to [the Joint Utilities'] GAM/PMM [proposal]."

4. When will responsibility for paying the PCIA end?

The Joint Utilities cite a number of information sources in response to this question:

- The Standard Data Matrix produced pursuant to the January 18, 2018 email communication from the ALJ provides the expiration date of each resource in the Joint Utilities' generation portfolios;
- The Joint Utilities also compiled three utility-specific "stacked up bar charts" that set forth the total forecast costs of the Joint Utilities' PCIA/CTC-eligible portfolios, which decline over time as contracts and other generation

resources “roll off” of the portfolios (*see* Total Cost Charts in Appendix D of Exhibit IOU-5).

The Total Cost Charts show separate components for UOG, RPS-eligible contracts, non-RPS contracts. The Total Cost Charts extend from 2018 through the end of the longest of the RPS contracts in the Joint Utilities’ respective portfolios, since the Current Methodology requires that these contracts remain PCIA-eligible for their tenured duration.

- The Joint Utilities also compiled three utility-specific charts that attempt to estimate and illustrate the “above-market” costs of the Joint Utilities’ portfolios over time (*see* Above-Market Charts in Appendix D of Exhibit IOU-5). The Joint Utilities note that those estimated costs are heavily dependent on many assumptions, as detailed in Exhibit IOU-5.

Other parties provide more insightful “takeaways” from Exhibit IOU-5.

Commercial Energy reviews the data and concludes “the extremely large rate impacts and the relative lack of success by the IOUs in marketing their excess resources to date highlight the need for the Commission to consider new approaches to the PCIA issue so that it can ensure bundled customer indifference without unduly exaggerating rate impacts on departing load customers. To do this, the Commission needs to consider market solutions that will actually attract market participants, as opposed to the traditional approach of simply mandating that costs be borne by particular stakeholders.”⁷⁷ Commercial supports its recommendations with the following summary of the data in Exhibit IOU-5:

⁷⁷ Commercial Energy opening brief at 6-7.

- PG&E's estimates its total PCIA eligible portfolio costs at nearly \$5.5 billion in 2018. That amount decreases to approximately \$750 million in 2044.
- PG&E estimates its above-market PCIA portfolio costs as approximately \$2.2 billion in 2018, decreasing to approximately \$250 million in 2044.
- SCE estimates its total PCIA eligible portfolio costs at \$2.9 billion in 2018, decreasing to around \$500 million in 2041.
- SCE's above-market PCIA portfolio costs sit at \$830 million in 2018, will increase to approximately \$940 million in 2026, and then decrease to just under \$100 million in 2041.
- SDG&E's PCIA-eligible portfolio costs total nearly \$1.1 billion in 2018, and are expected to decrease to approximately \$60 million in 2040.
- SDG&E's above-market PCIA portfolio costs are estimated at \$375 million in 2018, decreasing to \$20 million in 2040.

CalCCA totals the numbers in Exhibit IOU-5 and notes that the Joint Utilities estimate that from 2018 through 2041 their uneconomic portfolio costs will total an estimated \$49.68 billion, with more than half of that amount forecast for PG&E's service territory. Quoting its own testimony, CalCCA observes that "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."⁷⁸

⁷⁸ CalCCA opening brief at 1, quoting Exhibit CalCCA-1 at page 1-1. CalCCA reminds the Commission that the costs of the utilities' PCIA-eligible portfolios, including the uneconomic costs, are paid by all customers, including bundled utility customers.

5. Scope of PCIA-Eligible Resources and Costs

In this section of the decision, we resolve several contested issues regarding which utility resources and costs should be included in any cost recovery mechanism adopted in this decision. This issue was not specifically identified in the Scoping Memo but arose as a matter of controversy in parties' written testimony and subsequent briefs.

The Joint Utilities use the term "Eligible Resources" to refer to all the resources that would be subject to their own GAM/PMM proposal:

1. All resources that are now eligible for cost recovery under the Current Methodology.
2. The Joint Utilities propose that the Commission eliminate its current 10-year limitation on recovery of the uneconomic costs of certain resources. Instead these resources would remain Eligible Resources for whatever period is necessary for full utility recovery of their costs:
 - a. Post-2002 fossil UOG; and
 - b. Certain energy storage resources.

First, CalCCA opposes Commission removal of its existing 10-year cost recovery limitations. Second, CalCCA contends that the costs of "Legacy" UOG do not fall within the scope of costs that can be allocated to CCA departing load customers.⁷⁹ Third, CalCCA opposes proposals in this proceeding to exempt pre-2009 DA customers from any cost responsibility for Legacy UOG, if the same costs are imposed on CCA customers. CalCCA asserts this would result in undue discrimination.

⁷⁹ "Legacy" UOG is utility-owned generation installed before 2002.

Each of the disputes over the scope of PCIA-eligible resources and costs reflect parties' conflicting interpretations of the relevant statutory framework and Commission precedents regarding cost recovery of the relevant resources.

5.1. Legacy Utility-Owned Generation

CalCCA makes three arguments in support of its contention that the costs of Legacy UOG do not fall within the scope of costs that can be allocated to CCA departing load customers. First, CalCCA asserts that state law does not require CCA departing load customers to pay for Legacy UOG costs. CalCCA begins by citing AB 1890's provision that "allowed the utility to recover the above-market sunk costs of resources that would become uneconomic in the transition to competition through a nonbypassable charge to be paid by all electricity customers, regardless of supplier."⁸⁰ The Commission responded by establishing the "Competition Transition Charge" (CTC) and stated "With the exception of CTC arising from existing contracts, no further accumulation of CTC will be allowed after 2003 and collection will be completed by 2005."⁸¹

CalCCA contends that "nothing in the governing statutory framework has changed to permit recovery of [Legacy UOG] costs from departing load customers outside of the CTC"⁸² and, "Moreover, the Legislature made clear its intent *not* to recover the costs from CCA departing load customers in AB 117."⁸³ CalCCA contends that the Legislature "carefully prescribed the scope of costs

⁸⁰ Cal. Pub. Util. Code §367.

⁸¹ D.95-12-063 at 119.

⁸² CalCCA opening brief at 31.

⁸³ *Ibid.*

that must be recovered from CCA departing load to prevent a cost shift to bundled customers.”⁸⁴ These costs are listed below:

- Department of Water Resources bond charges, pursuant to § 366.2(e)(1);
- Department of Water Resources estimated net unavoidable electricity purchase contract costs, pursuant to § 366.2(e)(2);
- Unrecovered past undercollections for electricity purchases, including any financing costs, pursuant to § 366.2(f)(1); and
- A CCA customer’s share of the IOU’s estimated net unavoidable electricity purchase contract costs attributable to the customer, pursuant to § 366.2(f)(2).

CalCCA asserts that “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” but chose to include only the costs listed above in the scope of CCA departing load costs.⁸⁵ Finally, CalCCA asserts that no statute passed since that time has imposed Legacy UOG costs on CCA or any other departing load customer class.⁸⁶

CalCCA relies on “a well-settled canon of statutory interpretation in California law” to support its position: *Expressio unius est exclusio alterius* – “the expression of one thing implies the exclusion of others.”⁸⁷ CalCCA argues that, because the Legislature specified in AB 117 the costs that were to be borne by

⁸⁴ *Ibid.*

⁸⁵ *Ibid.*

⁸⁶ *Ibid.*

⁸⁷ CalCCA opening brief at 32, citing *Dyna-Med, Inc. v. Fair Employment & Housing Com.* (1987) 43 Cal.3d 1379.

departing load customers, under *expressio unius*, that list must necessarily be interpreted to be exclusive, unless a contrary legislative intent is expressed in the statute or elsewhere.⁸⁸

CalCCA's second argument in support of its contention that the costs of Legacy UOG do not fall within the scope of costs that can be allocated to CCA departing load customers rests on its assertion that the Commission's decision to include Legacy UOG costs in the PCIA was unrelated to, and did not materially benefit, CCA departing load. Here, CalCCA recounts the history that led to Commission decisions to include utility generation in departing load charges, and demonstrates that the inclusion was sought by DA parties because at the time, the above-market costs of the crisis-related DWR contracts would be offset by the benefits of lower-cost Legacy UOG.⁸⁹ This arrangement was continued in D.08-09-012, the Commission's decision on non-bypassable charges for new world generation, again because Legacy UOG was assumed to be "lower cost" than other resources, and therefore would have a mitigating or netting effect on overall departing load charges.⁹⁰ CalCCA recounts this history to support its argument that "while DA customers may have benefitted from this netting in the early years, CCAs do not appear to have similarly benefitted. PG&E[s] 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

⁸⁸ *Ibid.*

⁸⁹ CalCCA opening brief at 33, citing D.02-11-022 at 23.

⁹⁰ *Ibid.*, citing D.08-09-012 at 49-52.

consistently uneconomic, contributing \$545 [million] in uneconomic costs to PG&E's 2018 PCIA."⁹¹

CalCCA's third argument in support of its contention that the costs of Legacy UOG do not fall within the scope of costs that can be allocated to CCA departing load customers rests on its assertion that a Commission mandate that CCA customers continue to bear Legacy UOG cost responsibility, while exempting pre-2009 DA customers, would unlawfully discriminate against CCA customers. CalCCA suggests that "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 expired, there no longer was a need for [the] offset."⁹² CalCCA concludes

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."⁹³

The Joint Utilities' respond that CalCCA's proposal is without merit. First, the Joint Utilities assert that "if the Legislature wanted to exclude Legacy UOG

⁹¹ *Id.* at 34.

⁹² *Id.* at 35-36.

⁹³ *Id.* at 36. Section 728 provides, in pertinent part, "Whenever the commission, after a hearing, finds that the rates ... collected by any public utility for or in connection with any service...are insufficient, unlawful, unjust, unreasonable, discriminatory, or preferential, the commission shall determine and fix, by order, the just, reasonable, or sufficient rates ... to be thereafter observed and in force."

costs from CCA departing load cost responsibility in AB 117, it could have done so explicitly:"

The Legislature did not, as CalCCA contends, "decline[] ... to include these resources in the scope of CCA cost responsibility in AB 117." Nothing in Section 366.2 indicates such an intent. Section 366.2(f) states that CCA customers "shall reimburse the electrical corporation" for, among other things, the "net unavoidable electricity purchase costs attributable to the customers." It does not say that departing load customers "shall not" be responsible for an equitable share of other costs, including Legacy UOG costs.⁹⁴

The Joint Utilities appear to argue that even though the Legislature did specify costs for which CCA customers would be responsible, the fact that Legacy UOG was not on this list is immaterial because the Legislature did not provide a list of costs for which departing load customers "shall not" be responsible, even though it could have done so.

Second, the Joint Utilities argue that CalCCA's position is not supported by Section 366.2(a)(5), which states that the "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." Here, the Joint Utilities argue that the use of the word "shall" is clearly prospective in this context because the statute explicitly provides for cost allocation of historical

⁹⁴ Joint Utilities opening brief at 84.

electricity purchases. Legacy UOG, by definition, is not a prospective “generation procurement arrangement.”⁹⁵

Third, the Joint Utilities assert that CalCCA’s reliance on *expressio unius est exclusio alterius* (“the expression of one thing implies the exclusion of others”) fares no better because “statutes must be read to harmonize all of their various provisions and in light of their overall intent.” In the opinion of the Joint Utilities,

Section 366.2(a)(4) could not be more clear: “The implementation of a community choice aggregation program

⁹⁵ *Id.* at 84-85. Joint Utilities cite an argument earlier in their brief regarding the meaning of the words “shall” and “shall be”, which we provide verbatim here:

The words “shall be,” whether viewed through the lens of basic English-language interpretation, or in light of the fact that other sections of the statute explicitly authorize the allocation of historical procurement costs and contemplate an allocation of benefits, plainly mean “going forward.” Black’s Law Dictionary defines the verb “shall” as the future tense of the verb “will.” [internal cite: Black’s Law Dictionary (10th ed. 2014)]

The future tense of a verb is used to describe an event that will take place at some time in the future [internal cite: *Kelly v. State Personnel Board*, 31 Cal.App.2d 443, 446-447 (1939)]. The phrase “shall be” has a prospective meaning; it refers to something that will be done in the future, after the date of the enactment of the law or statute in question [internal cite: *Seale v. Balsdon*, 51 Cal. App. 677, 680-681 (1921) (interpreting the phrase “shall have been” to have a prospective meaning)].

While the Commission has held that there is “no authority that establishes verb tense should control our interpretation of the Public Utilities Code,” [internal cite: D.11-12-056 at 5] California state courts have determined that in construing statutes, the verb’s tense is significant [internal cite: *See, e.g., Matus v. Bd. of Admin. of Calif. Pub. Employees’ Ret. Sys.*, 177 Cal. App. 4th 597, 607 (2009), *see also Hughes v. Bd. of Architectural Examiners*, 17 Cal.4th 763, 776 (1998)].

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.”

In addition, the fundamental underpinning of the statutes put in place by both AB 117 (which authorized CCA formation), as well as relevant provisions of SB 350 (which clarified CCA formation rules), is the absolute prohibition on cost-shifting between customers.⁹⁶

Fourth, the Joint Utilities assert that CalCCA's arguments regarding discriminatory treatment of different customer groups is incorrect: “pre-2009 vintage departing load customers are differently-situated, as there are no long-term contracts in the IOU's portfolio for which they are responsible.”

CLECA attempts to clarify matters by explaining “here, the rationale that justifies the different treatment of pre-2009 DA customers is the use of the total portfolio methodology and the different vintages of the customers. For the pre-2009 DA customer vintages, there are no more above-market costs incurred on their behalf to be recovered through the PCIA.”⁹⁷

Regarding Legacy UOG as a whole, we find the statutory arguments offered by the Joint Utilities and TURN to be unconvincing: the Legislature did provide a list of costs in AB 117 for which departing CCA load would be responsible, and pre-2002 Legacy UOG is not on that list. We need not take the additional step suggested by the Joint Utilities, guessing what the Legislature may have included on a list of costs for which departing load would not be responsible. The Joint Utilities’ novel digression into the meaning of the words

⁹⁶ *Id.* at 86.

⁹⁷ CLECA reply brief at 3.

“shall” and “shall be” would have been more compelling had they not acknowledged that the Commission has previously held that there is no authority that establishes verb tense should control our interpretation of the Public Utilities Code. We also note that our own use of the word “shall” in ordering paragraphs is frequently a synonym for “must”.

TURN’s critique of CalCCA’s position is internally inconsistent: TURN states that “tellingly, CalCCA fails to cite a single Commission decision that embraces its narrow interpretation of the scope of costs eligible for recovery from departing loads”⁹⁸ but TURN itself cites no Commission decision that embraces TURN’s interpretation. Indeed, the instant decision is addressing this issue because the Commission has not done so previously.

Based on our review of the positions of the parties and their briefing of this issue, we conclude that the costs of Legacy UOG do not fall within the scope of costs that can be allocated to CCA departing load customers.

Regarding whether pre-2009 DA customer vintages should be exempted from responsibility for Legacy UOG costs, we have reviewed the arguments above, as well as relevant testimony and briefing submitted by AReM/DACC, and we find that parties who oppose CalCCA’s proposal have not met their burden to demonstrate why only “pre-2009 DA customer vintages” should not be responsible for pre-2002 Legacy UOG costs. Nor have these parties specifically identified any pre-2002 Legacy UOG resource and explained why CCA departing load should be responsible for the associated costs, but not pre-2009 DA customer vintages. The necessary distinctions may be crystal-clear to

⁹⁸ TURN reply brief at 11.

the handful of individuals who are directly affected by having to pay or not pay the relevant costs, but in the absence of convincing evidence in this proceeding that supports their position, we have no basis for agreeing with them. We decline to find that pre-2009 DA customer vintages should be exempted from responsibility for Legacy UOG costs, and we do not approve such an exemption in this decision.

5.2. 10-Year Limitation on Recovery of Post-2002 UOG Costs

The Joint Utilities argue that the Commission's current "presumption" of a 10-year limit on cost recovery of post-2002 UOG costs is in violation of Sections 365.2, 366.2 and 366.3, because "the requirement to equitably allocate the cost of Eligible Resources among bundled service customers and departing load customers is manifest and absolute, and applies for as long as procurement costs incurred by the Joint Utilities on behalf of the departing load customers continue to exist."⁹⁹ Therefore, the Joint Utilities contend that the 10-year limit must be eliminated, and post-2002 UOG resources must be treated in a manner consistent with all other Eligible Resources, in order to ensure that costs are not shifted to remaining bundled service customers.

Commercial Energy counters that the Commission should retain the 10-year limit:

The IOUs argue that the market conditions the Commission predicted when making that assumption have not come to pass and that, even in 2008, "th[e] assumption was questionable at best.

While the Commission's assumption has been rendered questionable by the IOUs' actual management practices, Commercial Energy does

⁹⁹ Joint Utilities opening brief at 29.

not believe that expecting the IOUs to manage their portfolios to reduce excess procurement is outlandish or unreasonable, particularly given the sizable increase in departing load that the IOUs themselves have documented.

The market-based mechanisms proposed in this proceeding—both the voluntary allocations and auctions—offer the IOUs the opportunity to make a concerted effort to reduce their non-RPS UOG resources, while also gaining market price insight for both themselves and the Commission. If, at the end of the 10-year period for a particular resource, the IOUs are truly unable to make a substantive reduction, the Commission can revisit the question of extended cost recovery on a case-by-case basis.¹⁰⁰

We view the Joint Utilities' request from a perspective similar to that offered by Commercial, and find that the 10-year limitation on recovery of post-2002 UOG costs should remain in place. Removing that limitation would also remove any incentive for the IOUs to manage their portfolios more aggressively to eliminate their long positions in non-RPS-eligible UOG. The Commission made the same point ten years ago in D.08-09-012. The Joint IOUs rely on what they view as a "manifest and absolute" statutory indifference requirement to support their argument, but we disagree that the statute relieves them from any responsibility to comply with our own decisions, such as D.08-09-012. Indeed, in its 2004 decision implementing AB 117, the Commission made a similar point at some length in its discussion:

The objective of AB 117 in requiring CCAs to pay a CRS is to protect the utilities and their bundled utility customers from paying for the liabilities incurred on behalf of CCA customers.

¹⁰⁰ Commercial Energy reply brief at 5. Commercial concludes by recommending that if the utilities ultimately sought to extend the 10-year limit, they should be required to demonstrate its efforts to monetize or otherwise allocate the resource(s) in question.

Our complementary objective is to minimize the CRS (and all utility liabilities that are not required) and promote good resource planning by the utilities.¹⁰¹

...

We share the parties' concerns that the utilities must recognize CCA load in their resource planning and should not sign contracts that might create new liabilities for CCA customers and utility customers where available information suggests the power might not be needed. We understand the utilities face a difficult balancing act by assuring adequate and reliable power supplies in amounts that reflect forecasts that are changing constantly. However, the utilities are accustomed to using available information to forecast customer demand and should incorporate CCA load losses into their planning efforts, just as they would include any other forecast variable related to expected changes in supply or demand.

We will address these matters in more depth in the utilities' resource planning applications and related dockets. With this in mind, we state our commitment to continue to coordinate CCA program elements with our oversight of utility procurement portfolios and resource planning. This should minimize unneeded power purchases by utilities and therefore the CRS.¹⁰²

We take further note that on the same day that the Commission adopted D.04-12-046 regarding CCA implementation, it also adopted D.04-12-048, which adopted PG&E, SCE and SDG&E's Long Term Procurement Plans in Rulemaking 04-04-003.¹⁰³ That decision also addressed the effect of departing load on utility procurement, noting that parties representing potential departing

¹⁰¹ D.04-12-046 at 29, emphasis added.

¹⁰² *Id.* at 30.

¹⁰³ R.04-04-003, Rulemaking to Promote Policy and Program Coordination and Integration in Electric Utility Resource Planning.

load by way of CCA, municipalization or DA “are all particularly concerned that the IOUs will over procure and then departing customers will be obligated to pay for their share of stranded costs so their departure will not over burden the bundled ratepayers remaining with the utilities.”¹⁰⁴ The Commission discussed all parties’ concerns regarding what it termed “potential stranded costs due to customer load uncertainty” and acknowledged the challenges presented by the then-new RPS and RA requirements: “these initiatives, combined with the existing overhang of utility retained generation and long-term DWR contracts significantly limit the flexibility that the utilities have to quickly adjust their resource portfolios.”¹⁰⁵ The Commission concluded that the utilities should be allowed to recover the net costs of these commitments from all customers, including departing customers, but “only the uneconomic portion” and specified that “the utilities must take appropriate steps to minimize their costs by selling excess energy and capacity needs into the marketplace.”¹⁰⁶ The Commission also ordered that “in future procurement plans, the IOUs shall incorporate reasonable anticipated CCA departing load. The assumption of the Commission is that the IOUs shall acknowledge potential CCA departing load and identify which city and/or county has expressed intent to pursue aggregation, including MW estimates of this departing load, in future procurement plans.”¹⁰⁷

Despite the Commission’s longstanding and consistent direction to avoid over-procurement and minimize portfolio costs, in this proceeding the Joint

¹⁰⁴ D.04-12-048 at 18.

¹⁰⁵ *Id.* at 57.

¹⁰⁶ *Id.* at 59.

¹⁰⁷ *Id.*, Ordering Paragraph 9.

Utilities ask that we adopt seemingly limitless provisions to hold departing load responsible for more and more resources in their portfolios. The record in this proceeding clearly demonstrates that this approach is not workable, and the Joint Utilities have not made a convincing showing regarding what actions, if any, they have taken since 2004 to comply with the Commission directives outlined above. For these reasons, the imperative from this point onward will be to work toward portfolio optimization and cost reduction, and leave behind static portfolio management and the associated cost recovery of above-market costs for utility-held resources that are no longer needed by the bundled customers that they serve. We deny the Joint Utilities' request that we remove the 10-year limit on cost recovery of post-2002 UOG costs.

Finally, we note that our determination does have the effect that only bundled customers and direct access customers will bear responsibility for post-2002 UOG costs. We emphasize again that at the time the Legislature adopted the underlying statutes, and the Commission implemented that direction, the Commission expected that the utilities would work diligently to reduce or eliminate future liabilities. To the extent that has not happened, this is not a reason to impose these costs on CCAs, and "cost shifting" is not an issue here.

5.3. 10-Year Limitation on Recovery of Energy Storage Resource Costs

In D.14-10-045 the Commission approved each of the Joint Utilities' energy storage procurement proposals and authorized recovery of above-market costs through the PCIA, but denied requests for extension of the PCIA mechanism for market/"bundled" energy storage contracts beyond 10 years.¹⁰⁸ The

¹⁰⁸ D.14-10-045, Ordering Paragraph 1(3) and 1(4).

Commission explained that that potential implementation of PCIA for generation and non-generation in future energy storage solicitations involves complex policy, equity, cost, implementation, and market impact considerations against the backdrop of new and emerging technologies.¹⁰⁹ For these reasons, the Commission found that energy storage cost recovery and allocation issues require ongoing and broader scrutiny and detailed consideration regarding pros and cons of various approaches that apply to various levels of the grid domain.¹¹⁰

The Joint Utilities make arguments similar to those we dismissed above in support of this request. In D.14-10-045, in addition to the findings regarding the complexity of these cost recovery and allocation issues, the Commission also concluded that it is reasonable that the IOUs have the burden of proof to demonstrate circumstances that warrant PCIA treatment for specific proposed energy storage procured for bundled service, and that the Commission should consider other venues such as workshops or OIRs to help resolve outstanding issues involving PCIA treatment for subsequent solicitations or the extension of PCIA treatment to the life of the contract beyond 10 years.¹¹¹

This proceeding simply has not considered energy storage “stranded cost” recovery in the manner contemplated by the Commission in D.14-10-045. Testimony addressed none of those issues, nor did briefs. The Joint Utilities have not met their burden of proof regarding their request that the Commission eliminate the ten-year limit on allocation of the above-market costs of PCIA-

¹⁰⁹ *Id.*, Finding of Fact 33.

¹¹⁰ *Id.*, Finding of Fact 37.

¹¹¹ *Id.*, Conclusions of Law 31 and 32.

eligible energy storage resources to departing load customers. Therefore we deny the Joint Utilities' request.

6. Adopted Portfolio Valuation and Allocation Methodologies

In this section of the decision, we address Issue 3 and Issue 4 from the Scoping Memo:

3. If the current PCIA methodology does not prevent cost-shifting between bundled utility customers and CCA and DA customers, can that methodology be revised to ensure that cost increases are prevented for bundled and departing load?
4. If not, what replacement methodology should the Commission adopt in order to meet the statutory requirement to ensure that bundled retail customers shall not experience any cost increases as a result of either (1) retail customers of an electrical corporation electing to receive service from other providers or (2) the implementation of a CCA program, and 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.

In Section 4 of this decision we found that the current PCIA methodology does not prevent cost-shifting. Here, we consider parties' recommended solutions and adopt the approach that best achieves the overall goal of this proceeding, in a manner consistent with the guiding principles articulated in the Scoping Memo.

Although the parties' common briefing outline addressed the issues of portfolio valuation and allocation sequentially, we address them together here because that best allows us to explain the central result we reach in this decision: we leave the current PCIA framework in place, but we adopt new benchmarks for the RPS Adder and the RA Adder in order to improve the initial accuracy of

the PCIA that will be in effect each year. We also adopt an annual true-up requirement in order to ensure that any forecast-related errors in the annual PCIA are reconciled and cost-shifting is prevented.

6.1. Positions of the Parties

This section presents the positions of the parties on the proposals summarized above.

ACC recommends that the Commission consider making straightforward updates to the PCIA benchmark methodology while it takes more time to consider parties' proposals for transferring attributes of existing contracts. ACC sees merits and drawbacks to both the GAM and the PMM.

AReM/DACC indicates that of the options available now to the Commission, believes that a modified PCIA would be significantly more predictable, understandable and transparent than new proposals such as the Joint IOUs' GAM/PMM proposal. That said, AReM/DACC also agrees with the Joint IOUs that the Commercial VAAC proposal "offers some potentially creative solutions and includes elements that may warrant further consideration."¹¹² As CalCCA's securitization proposal, AReM/DACC would support Commission direction consider the VACC proposal in a follow-on proceeding to establish the implementation details.

Brightline agrees that the GAM and PMM methodologies improve upon the PCIA and offers minor suggestions to make these methodologies stronger. Additionally, Brightline agrees with TURN, that the proposals submitted by various parties are not mutually exclusive and would support a decision by the Commission to implement certain aspects of various proposals.

¹¹² AReM/DACC opening brief at43-44.

CalCCA, as noted above, 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. Therefore, CalCCA opposes the GAM/PMM proposal, contending that it threatens the Commission's ability to fulfill the statutory mandate pursuant to section 366.2(a)(5) that a CCA "shall be solely responsible for all generation procurement activities on behalf of the CCA's customers."¹¹³

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.¹¹⁴

In its opening brief, Commercial Energy "in essence" recommends that the Commission adopt parts of three parties' proposals: (1) its own VAAC concept; (2) a residual PCIA charge that works in much the same way as the final stages of the PMM proposed by the IOUs; and (3) a combination of options to reduce the above-market resources in the IOU portfolios, through securitization of UOG resources, buy-downs and buy-outs of contract costs, and forward sales of IOU resources, as proposed by CalCCA and other parties.¹¹⁵ Commercial contends that together, these proposals will serve to "update and improve the existing PCIA mechanism, create true market price transparency and cost certainty, and maintain customer indifference. This combination of solutions will also provide

¹¹³ CalCCA opening brief at 8.

¹¹⁴ *Ibid.*

¹¹⁵ Commercial Energy opening brief at 2.

a greater incentive for LSEs to participate in market mechanisms to either reduce or make use of the excess above-market resources in the IOU portfolios.”¹¹⁶

CLECA recommends that the Commission continue to use the current methodology, with reformed benchmarks. Although CLECA expressed concern about using a PCIA true-up in its served testimony, in its brief CLECA explains that it now recommends adoption of “a true-up paired with a collar on the range of potential changes to the PCIA to address volatility concerns.”

CUE faults the current PCIA methodology because it uses administratively determined benchmarks and forecast costs rather than actual revenues and actual costs so there is cost shifting between bundled customers and departing customers. CUE also notes that the PCIA does not completely allocate the benefits of the IOUs’ Legacy contracts to departing customers. CUE supports the Joint IOU proposal because it is the only proposal that eliminates cost shifting, is scalable and ready to implement; CUE asserts that “the other proposals are still under development and/or would not eliminate cost shifting.”¹¹⁷ CUE explains that the market price benchmark methodology should be eliminated and the value of the IOU portfolios should be based on actual market prices. Therefore, CUE finds that the Joint IOU proposal achieves customer indifference by using actual market costs and revenues to calculate above-market costs, followed by an annual true-up. However, CUE also finds that the Joint IOU proposal to allocate unbundled RECs to satisfy certain RPS requirements is not consistent with the

¹¹⁶ *Ibid.*

¹¹⁷ CUE opening brief at 17.

law or Commission policy. CUE offers no means of reconciling this problem in time to implement the GAM/PMM in 2019.¹¹⁸

CMTA recommends that the Commission make no changes at this time. Instead, the current PCIA methodology should remain in place and a new phase of this proceeding should be opened “in order to resolve the still open questions in the Scoping Memo, help the Commission make the most informed, fair and balanced decision for a modified or replacement PCIA methodology and allow sufficient time to develop a long-term solution of the issues.”¹¹⁹

CLECA recommends that the Commission retain the current methodology and existing benchmark for brown energy while reforming the RPS and capacity adders.

The City of San Diego asserts that the Joint Utilities have not met burden their with respect to GAM/PMM proposal, so it should not be adopted. In addition, the City cites evidence that indicates that the GAM/PMM proposal would be significantly more impactful on customer choice in the SDG&E area, but observe that “since the Joint Utilities provide no detailed analytical support for their proposal, it was not possible for parties to probe the reasons for these disparate results.”¹²⁰ For these reasons, the City recommends that PCIA reform

¹¹⁸ *Id.* at 19-21. Regarding its concerns about unbundled RECs, CUE suggests that “Instead of the IOUs allocating unbundled RECs, the Commission may wish to encourage longer term forward sales of *bundled* renewable energy *and* RECs. This would preserve the PCC status of the RECs without question, maximize the REC value by satisfying statutory requirements for buyers, and eliminate double procurement for RPS compliance.”

¹¹⁹ CMTA opening brief at 6.

¹²⁰ City of San Diego opening brief at 8, citing Exhibit AD-02 at 23-24 (Compare Figures 2 and 4 to Figure 3).

begin with “relatively simple changes to the PCIA” identified by AReM/DACC and others.¹²¹ For the City, these changes would include revision to the green adder to incorporate long term renewable values and reforming the Department of Energy green adder reference point, correction of the value of capacity and RA, and transparency enhancements.

The Joint CCAs recommend adoption of CalCCA’s proposal because they find it to be the best alternative to the current PCIA: it addresses customer indifference through a modified status quo, with the ability for long-term restructuring and optimization of the Joint Utilities’ portfolios.

The Joint Utilities address assertions that the Commission should look beyond the market in determining the value of Eligible Resources and discuss suggestions that the Joint Utilities’ energy supply contracts include inherent, but unquantifiable, “long-term value” that transcends how the market values them. The Joint Utilities also assert that any proposal to reform the PCIA that relies on the exclusive use of market price benchmarks, with or without a true-up, is problematic: “while it would be relatively straightforward to ‘true-up’ for energy sales, revenues, and generation volumes after the fact (because energy is transacted transparently in a liquid market) ... the same is not true of RA and RECs.”¹²²

ORA supports the GAM/PMM provided that ERRRA processes are updated to allow for thorough review of resource cost assumptions:

¹²¹ *Id.* at 9.

¹²² Joint Utilities opening brief at 11. These concerns aside, the Joint Utilities stress that “a true-up is absolutely necessary,” just not sufficient to prevent cost shifting, in their opinion.

If the Commission approves the GAM/PMM method, then the Commission should ensure that ERRA processes are updated to include an open review process which would allow the Commission and ORA to review all assumptions. The existing process for reviewing the PCIA under ERRA is not adequate for rigorous review of the proposed GAM/PMM method.¹²³

ORA also recommends that the Commission value IOU portfolios using only products which have real value in existing markets: if there is additional value associated with various RA or RPS products, the Commission should use actual transactions to assign value.¹²⁴ More broadly, ORA supports a true up mechanism for whichever valuation and/or allocation method is adopted: “the true up should be based on products which are transacted in the market and for which a transparent and verifiable amount is readily identifiable.”¹²⁵

POC’s position is that cost shifts occur whenever bundled load continues to extract the full value of long-term contracts retained in the utilities’ portfolios, while departing load is credited only the more limited value associated with short-term sale of resources held under those contracts.¹²⁶ To prevent cost shifts between bundled and departing load, the Commission should require the Joint Utilities to optimize their monetization of portfolio resources by assigning contract rights to CCAs or ESPs and by engaging in forward sales of resources

¹²³ ORA opening brief at 13.

¹²⁴ *Id.* at 9-12.

¹²⁵ *Id.* at 6.

¹²⁶ Protect Our Communities opening brief of at 26, citing Exhibit UCAN-01 at 9.

where contract rights cannot be assigned.¹²⁷ More generally, POC recommends that any valuation methodology, including the use of benchmarks for resources maintained in utility portfolios, should ensure that departing load is credited for hedging and optionality values associated with long-term contracts as well as for premiums associated with delivery of energy from greenhouse gas free resources. POC supports the continued use of a multi-year average of newly delivering RPS-eligible contracts to set the RPS adder as a reasonable proxy for the market value of green energy delivered in the benchmark year. For these reasons, POC recommends that the Commission adopt a PCIA methodology that credits departing load for hedging and optionality values associated with long-term contracts as well as premiums associated with delivery of energy from greenhouse gas-free resources. POC finds that CalCCA's proposed modifications to the Current Methodology represent the soundest strategy to capture and credit departing load for the value of PCIA-eligible resources.¹²⁸

UC recommends focusing the initial efforts in this proceeding on making course corrections to the existing PCIA rather than creating an entirely new exit fee structure, because "the stakes of the changes to the PCIA are extremely high and dramatic changes to the PCIA could upend California's electricity industry."¹²⁹ UC support the types of incremental changes proposed by AReM/DACC and oppose the Joint IOUs' Green Allocation Mechanism because it is inconsistent with and disruptive to UC's Portfolio Management Strategy:

¹²⁷ *Ibid.*, citing testimony at hearing of TURN witness Woodruff (RT at 1085:10-1086:5) and Exhibit UCAN-01 at 15.

¹²⁸ Reply brief of Protect Our Communities at 15.

¹²⁹ Opening Brief of the Regents of the University of California at 5.

In particular, the mandatory allocation of resource adequacy (RA) attributes and renewable energy credits (RECs) to DA customers may interfere with and complicate UC's selection of portfolio resources consistent with the policies and preferences of the various UC campuses. UC's portfolio strategy is to cultivate a mix of long and shorter term procurement with a variety of renewable and carbon-free sources. With ongoing load reductions from energy efficiency and variable net load resulting from considerable behind-the-meter generation, procurement flexibility is needed to reach carbon neutrality in a way that is both cost-effective and simultaneously compliant with the wide variety of existing LSE regulations.¹³⁰

Shell Energy (Shell) prefaces its recommendation by noting that determining whether a “cost shift” is occurring when customers depart for DA or CCA service requires an assessment of the “net unavoidable costs.” Shell relies on CalCCA’s definition of “net unavoidable costs”: “portfolio costs, net of benefits or value, that cannot be avoided through prudent utility procurement and portfolio management.”¹³¹ For Shell, then, a key consideration in the PCIA methodology is an accurate valuation of the resources in the IOU’s portfolio. Shell focuses on the dichotomy that the Joint Utilities’ portfolios

are largely comprised of resources under long-term contracts, yet the PCIA’s current market benchmark is based on short-term prices.

Short-term market prices are not an appropriate measure of the value of long-term resources. The short-term market does not capture all of the value embedded in a long-term resource held by an IOU. CalCCA witness Hoekstra testified: “[U]sing

¹³⁰ *Id.* at 7.

¹³¹ Shell Energy opening brief at 3-4, citing Exhibit CalCCA-1 at page 2A-1.

short-term prices for products held in the long-term portfolio retains the option value of the assets for bundled customers [,] but requires departing load to pay the cost of bearing the downside price risk for bundled customers without compensation.”¹³²

Shell concludes that the current PCIA benchmark must be adjusted to include a proper (and separate) valuation of long-term and short-term resources, a distinct valuation of ancillary services provided by resources in an IOU’s portfolio, and valuation of all GHG-free resources at an adjusted RPS benchmark level.¹³³

Solana Energy Alliance recommends that the Commission retain the existing PCIA framework with necessary modifications, instead of adopting the GAM and PMM proposals. Solana asserts that a modified PCIA framework will provide the best structure in which to assess and reassess portfolio values over time, in part because the Commission has the most experience with it. Solana raises concern that the GAM and PMM proposals are new and untested; like the City of San Diego, Solana also cites evidence that these proposals would result in substantially different departing load charges in different IOU territories, including disproportionate effects in SDG&E territory: “What concerns SEA in particular is that the IOU proposals may require CCA and DA customers in SDG&E territory to pay substantially higher charges than customers in PG&E and SCE territory. That raises questions about fairness and equity, but also raises questions about [portfolio valuation] methodology.”¹³⁴

¹³² *Id.* at 4, citing Exhibit CalCCA-1 at 2A-4.

¹³³ *Id.* at 5.

¹³⁴ Opening brief of Solana Energy Alliance at 8. Solana cites Exhibit AD-02 at 22 and 23, wherein AReM/DACC provides discovery from the Joint IOUs showing their calculations of what the GAM and PMM charges would have been in 2018 had they

Footnote continued on next page

TURN provides a thorough analysis of the problems with the existing market price benchmarks and concludes that the current PCIA methodology must be modified to reconcile any forecasted values with actual market transactions, through a true up process that reconciles differences between forecasted and actual values. TURN further recommends (1) modifying the benchmark's forecast capacity value to reflect the RA capacity costs included in the Commission's Energy Division's Resource Adequacy Report while assigning a zero or *de minimis* price for capacity expected to remain unsold, and (2) modifying the benchmark's renewable power value to reflect the pricing reported by all LSEs for purchases and sales of renewable energy in the prior year for deliveries occurring in the forecast year.

TURN also asserts that the Joint Utilities' proposed Green Allocation Mechanism is impermissible as a matter of law and unreasonable as a matter of policy.

UCAN recommends that the Commission adopt its proposed modifications to the current PCIA mechanism to capture value for:

1. long-term contract and where applicable UOG assets;
2. all RA and ancillary services;
3. RECs;
4. option and hedge value; and
5. a long-term GHG adder.

been adopted. AR AReM/DACC explain: "For the latter vintages for SDG&E, the [G]AM + PMM is about 2.5-3.0¢/kWh more than the current PCIA. Per the IOU's calculations, the SDG&E PMM alone would equal the current PCIA, with the GAM being fully incremental."

UCAN considers its recommendations to be essentially aligned with CalCCA, POC, Shell Energy, AReM/DAC, COG, and CLECA. UCAN believes that its approach differs from the positions taken by Joint Utilities, TURN, and ORA.

6.2. Discussion

We have reviewed the in-depth analysis provided by parties, and evaluated the merits of the proposals before us within the context of the guiding principles established in the Scoping Memo. We conclude that the best course of action that is consistent with California's ambitious public policy goals, ensures compliance with the law, and protects customers is the approach that reflects the view shared among many parties: adopt a corrected benchmark methodology to determine the PCIA and open a second phase of this proceeding to consider the development and implementation of a comprehensive solution to the issue of excess resources in utility portfolios, one that is based on voluntary, market-based resource redistribution. We discuss those longer-term matters in the next section of this decision.

In addition to the revised benchmarks that we describe below, we also adopt a true-up mechanism, as recommended by a number of parties, as well as a PCIA rate collar with a floor and a cap that will limit the change of the PCIA from one year to the next. The true-up will ensure that bundled and departing load customers pay equally for PCIA-eligible resources. The cap will provide a degree of stability and predictability as sought by parties representing departing load interests. Finally, we take an additional step toward the simplicity and predictability requested by departing load customers by adopting a prepayment option. We address the details of these mechanisms in the Implementation section of this decision.

6.2.1. Revised Methodology for Calculating the Market Price Benchmark

First, the methodology for calculating the Brown Power Index shall not change and shall be calculated and made available by the Commission's Energy Division as is currently done, at the end of October each year.

Second, we adopt TURN's approach for estimating the RPS Adder. We appreciate that TURN frankly acknowledges the difficulties presented by limited sources of transparent price data, but still offers a credible approach to developing as accurate an estimate as possible. We do change the data requirements to more realistically account for when reported data actually becomes available. The RPS Adder shall be calculated using the reported prices of purchases and sales of renewable energy by the IOUs, CCAs and ESPs during the year two years prior to the forecast year ("year n-2") for delivery in the forecast year ("year n").¹³⁵ For example, the RPS Adder for 2020 would be calculated using data from 2018.

Third, we adopt TURN's proposal for estimating the RA Adder, which shall be calculated using reported purchase and sales prices of IOU, CCA, and ESP transactions made during (year n-1) for deliveries in (year n).¹³⁶ A zero or *de minimis* price shall be assigned for capacity expected to remain unsold.¹³⁷ As with the RPS Adder, we find that TURN's approach to reconciling limited sources of transparent price data and developing as accurate an estimate as possible is credible.

¹³⁵ Exhibit TURN-1 at 9.

¹³⁶ *Ibid.*

¹³⁷ *Id.* at 10.

We also adopt CLECA's proposal that the RA Adder be changed to reflect the three types of RA capacity: system, local, and flexible.¹³⁸

- The Energy Division's annual RA report, which compiles data provided by LSEs on a confidential basis, shall be modified as necessary to reflect data collected separately for each type of RA:
 - RA that provides both system and flexible capacity shall be counted as flexible capacity
 - RA that provides both system and local capacity shall be counted as local RA capacity
 - If the RA provides all three types of RA capacity, it shall be counted as local capacity
- Local capacity values shall be differentiated by Transmission Access Charge area.

6.2.1.1. New Reporting Requirements

As part of its recommendations regarding the RPS Adder, TURN recommends that the Commission establish new transaction reporting requirements for CCAs and ESPs to ensure that the RPS Adder is as accurate as possible. We adopt the following additional requirements:

- Contract information shall be collected for all LSE contracts executed in year n-2, with year n being the year from which the PCIA calculation is being done.
- Contract information shall include: seller name, execution date, contract price (\$/MWh), term length of contract, capacity (MW), associated Net Quantifying Capacity (NQC), annual expected generation (MWh/year), expected generation for year n.

¹³⁸ Exhibit CLECA-1 at 19-20; CLECA reply brief at 7.

- If a contract includes Time of Delivery (TOD) adjustments, then the contract's price shall be TOD-adjusted.
- Energy Division shall collect this information in a common data template for each LSE by January 31 of year n-1 and calculate a weighted average RPS contract price (\$/MWh) for RPS energy to be delivered in year n from contracts executed in year n-2.
- This figure would be made available at the end of October of year n-1, like the brown benchmark.

We provide additional direction in the "Implementation" section and Appendix 1 of this decision.

6.2.2. Annual True-up

TURN notes that "the Commission has long used true ups to reconcile discrepancies between forecast and actual values."¹³⁹ With respect to procurement costs, the Commission's ERRR ratemaking process relies on an annual forecast to set each IOU's annual revenue requirement, and then allows the IOUs to track their actual costs and actual revenues in the ERRR balancing account, so that any overcollection or undercollection is "trued up" and used to adjust a subsequent annual revenue requirement either upwards or downwards. TURN asserts that "it would be unreasonable to use true-ups only for determining the cost responsibility of bundled service customers and not for calculating the cost responsibility for departing loads..."¹⁴⁰

TURN proposes the following true-up process:

At the end of the year, the net costs of the PCIA resources should be calculated based on the recorded gross costs of the

¹³⁹ TURN opening brief at 15.

¹⁴⁰ *Id.* at 16, citing Exhibit TURN-2 at 1.

resources minus the revenues such resources earn in relevant markets [footnote: ...this year-end reconciliation would also effectively true-up forecasted and actual generation quantities]. These markets would include sales into the energy and ancillary services markets operated by the CAISO along with revenues from forward sales of energy, renewable energy and RA capacity to other market participants. Any unsold resources or attributes would be assigned a market value of zero for purposes of determining the ultimate PCIA charge.

ORA envisions a true-up based on actual portfolio performance and market settlement data: “These costs could be audited and verified in the IOUs’ ERRR Compliance applications.”¹⁴¹

We agree that an annual true-up process should be adopted. We discuss the details of the adopted mechanism below, in the “Implementation” section of this decision.

6.2.3. Caps, Floors, Collars and Sunsets

In this section of the decision, we address Scoping Memo issues 9 and 10, which posed the following questions to parties:

9. Should the Commission “cap” the PCIA or an alternative cost allocation method?
10. Should the Commission adopt a sunset of the obligation to pay the PCIA or an alternative cost allocation method?

We address these questions in reverse order, because our first determination here is that the Commission should not adopt a sunset of the obligation to pay the PCIA; this informs our discussion of parties’ proposals to “cap” the PCIA.

¹⁴¹ ORA opening brief at 12.

6.2.3.1. Sunset of the Obligation to Pay the PCIA

CalCCA states that the Commission should make a finding in this case regarding a defined sunset date for stranded costs, because “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.”¹⁴²

CLECA recommends that the Commission should set a sunset period for cost recovery after it has addressed the high-priced RPS contracts for which cost recovery is set for the term-of-contracts.

Commercial Energy opposes placing a sunset provision on the PCIA because a sunset provision will reduce incentives for parties to actively participate in any allocation or auction process that the Commission might adopt.¹⁴³

CUE opposes a sunset on the PCIA, because it would result in cost shifting: “By arbitrarily limiting the number of years of the PCIA, bundled customers would have to pay for resources that were acquired to serve departing load after the sunset of the PCIA.”¹⁴⁴

The Joint Utilities echo CUE, and also assert that pursuant to Section 366.2(f)(2) “a CCA customer’s cost responsibility exists ‘for the period commencing with the customer’s purchases of electricity from the community

¹⁴² CalCCA opening brief at 141.

¹⁴³ Commercial Energy Opening brief at 36.

¹⁴⁴ CUE opening brief at 26.

choice aggregator, through the expiration of all then existing electricity purchase contracts entered into by the electrical corporation’.”¹⁴⁵

Shell Energy supports a sunset and/or a fixed “cap” on a departing customer’s PCIA cost responsibility.

UCAN supports both a cap and a sunset provision for the PCIA, with the sunset taking effect seven years from now.

Although we acknowledge parties’ reasons for supporting a sunset provision, we conclude that such a provision should not be adopted in this decision. First, we agree with the Joint Utilities that Section 366.2(f)(2) bars the Commission from sunsetting CCA customer obligations vis a vis the “expiration of all then existing electricity purchase contracts”. We also agree with Commercial Energy that a sunset provision will reduce incentives for parties to actively participate in any allocation or auction process that may take place in the second phase of this proceeding.

6.2.3.2. Should the Commission “Cap” the PCIA rate?

TURN notes that “The potential for significant annual fluctuations in the PCIA charges can complicate individual LSE planning efforts by creating cost uncertainty that may limit their ability to procure over longer time horizons and thereby frustrate clean resource development objectives.”¹⁴⁶ TURN recommends the Commission address this concern by adopting a limit on year-over-year increases to the PCIA equal to 0.5 cents/kWh for any PCIA charge above

¹⁴⁵ Joint Utilities opening brief at 80.

¹⁴⁶ TURN opening brief at 33.

1.5 cents/kWh. If annual increases in the PCIA rate remain below that level, no cap would be applied.¹⁴⁷

AReM/DACC opposes an annual true-up mechanism for the PCIA, but states that if a true-up is adopted, its proposed rate collar “becomes essential.”¹⁴⁸ AReM/DACC recommends that the Commission adopt a PCIA rate collar whereby the PCIA is capped at 2.2 cents per kWh while also limited by a “floor” of zero cents per kWh. The floor ensures that the PCIA cannot “go negative” and require that bundled customers pay departing load customers if the PCIA calculation would otherwise require that result. According to AReM/DACC, “the unknown volatility that the true-up could cause to the PCIA needs to be tempered by rate protections, both for departing customers (the PCIA cap) as well as bundled customers (AReM/DACC’s proposed PCIA floor). AReM/DACC asserts that the floor and the cap would protect all customers, bundled and departed alike.¹⁴⁹ AReM/DACC suggests that the Commission consider “implementation of a cap that combined the features of its and the TURN cap proposals. For example, the collar could initially be set at AReM/DACC’s recommended 2.2¢/kWh, and have it change per the TURN proposal.”¹⁵⁰

Brightline observes that caps on the PCIA charge could provide benefits such as predictability, a guiding principle in this proceeding. However, Brightline also suggests that caps could “result in a cost shift to bundled

¹⁴⁷ *Id.* at 34.

¹⁴⁸ AReM/DACC opening brief at 38.

¹⁴⁹ AReM/DACC reply brief at 15-16.

¹⁵⁰ *Id.* at 16.

customers if the IOUs increase their rates in order to make up for the revenue that has not been collected, especially if a large percentage of customers suddenly departs as could happen if the planned CCAs do become operational.”¹⁵¹ To address such concerns, the Commission could adopt caps with increasing scalars. In any event, since caps present the potential for both benefit and drawbacks, Brightline recommends that any caps the Commission implements should be reviewed intermittently to determine if they result in increased accumulations in balancing accounts or cost shifts, particularly to bundled customers. If either scenario occurs, the Commission could eliminate or adjust the caps.¹⁵²

CLECA also supports consideration of a cap on the PCIA, if the cost minimization proposals it suggests be pursued by the Commission “fail to reduce the cost responsibility that has to be shared to a non-disruptive level.”¹⁵³ CLECA explains that “use of an annual true-up to capture the actual versus the forecast above-market value of relevant resources paired with a collar on the potential year-to-year changes to the PCIA to address volatility concerns would comply with several of the guiding principles articulated in the Scoping Memo:

The Commission's primary guiding principle is for the methodology to achieve verifiable, transparent results. Thus, first, the trued-up result will be verifiable and transparent, particularly for parties willing to execute non-disclosure agreements to access confidential data. Customer representatives--of both bundled customers and departing customers--can examine and compare the forecast cost responsibility with the actual cost responsibility. Second, pairing

¹⁵¹ Brightline opening brief at 11-12.

¹⁵² *Id.* at 12.

¹⁵³ CLECA opening brief at 6.

the true-up with imposition of a collar on the range of permitted change in the PCIA should assuage departing customer concerns regarding the volatility of the PCIA and their need for stability.⁶⁸ Addressing volatility to enable “reasonably predictable outcomes that promote certainty and stability” meets the Commission's secondary guiding principle.

CUE offers the pragmatic assessment that while a cap on the PCIA is not ideal, it could address concerns about uncertainty if done correctly. CUE acknowledges that some parties have expressed concerns about uncertainty in year-to-year changes in PCIA charges and supports TURN's proposal for that reason. However, CUE emphasizes that any resulting over- or under-collections in a given year “must be tracked in a balancing account to be refunded or collected in the following year. CUE opposes any cap where over- or under-collections are not fully repaid or recouped within one year because of the resulting cost shifts.”¹⁵⁴ CUE acknowledges that any under-collections due to a cap would result in a cost shift, but notes that “it would be temporary and, therefore, is reasonable to balance uncertainty.”¹⁵⁵

The Joint Utilities oppose a cap because it would result in a cost increase for bundled service customers, even if theoretically only temporary, and would therefore violate “the statutory indifference principle established under Sections 365.2, 366.2 and 366.3.”¹⁵⁶

We find that the potential for volatility supports adoption of a PCIA collar in this decision. Each utility shall establish an interest-bearing balancing account

¹⁵⁴ CUE reply brief at 22.

¹⁵⁵ CUE opening brief at 26.

¹⁵⁶ Joint Utilities opening brief at 70-71.

that shall be used in the event that the cap is reached to track any obligation that accrues for departing load customers. Because any balances in the account will be repaid to bundled customers with interest, our adopted collar mechanism does not violate Sections 365.2, 366.2 and 366.3.

6.2.4. Prepayment

The Scoping Memo includes as issue 7(d) the question of whether the Commission should adopt options for customers to prepay the PCIA on a one-time basis, to be relieved of the PCIA burden going forward.

AReM/DACC suggests that “the Commission may not fully appreciate the degree to which educational, governmental, commercial and industrial DA customers desire certainty as to energy costs. Moving to direct access is in fact often largely motivated by certainty--the ability of a customer to negotiate pricing for a definitive term without being subject to the potential variability of utility pricing.”¹⁵⁷ For these reasons, AReM/DACC recommends that DA customers be permitted to pre-pay their PCIA obligations, conditioned upon the following specific terms:

- It would be based on a mutually acceptable forecast of that customer's future PCIA obligation;
- It could be either (a) one-time; or (b) a series of levelized payments over 2-5 years;
- It would not be trued-up;
- Once the pre-payment has been made, the customer would not receive any refunds if it returns to bundled service; and
- Once paid, the customer could switch among competitive retail sellers without incurring any new PCIA obligation.

¹⁵⁷ AReM/DACC opening brief at 36-37.

CalCCA also recommends that the Commission authorize prepayment of departing load cost responsibility. CalCCA asserts that prepayment would not shift costs among bundled and departing load customers, and notes that (1) the Commission has previously directed the utilities to permit California publicly owned utilities to prepay departing load obligations,¹⁵⁸ and (2) commercial customers in other states have prepaid bundled service obligations when departing utility service.¹⁵⁹ CalCCA suggests that a prepayment calculation could rely on values from its recommended Staggered Portfolio Auction, or could be achieved through bilateral negotiations, subject to Commission approval on a case-by-case basis.

CLECA agrees with CalCCA and AReM/DACC that departing customers should be allowed to buy-out their PCIA obligation, and recommends the Commission approve the formula and parameters proposed by AReM/DACC for such purposes.¹⁶⁰

Commercial Energy does not oppose negotiated buyouts of PCIA cost responsibility, suggesting that “the Commission view such options as a longer-term measure to reduce the IOUs’ PCIA portfolios.”¹⁶¹

¹⁵⁸ CalCCA opening brief at 134: “In 2007, Commission Resolution E-3999 directed the IOUs to offer bilateral agreements to publicly owned utilities (with departing load customers) as an alternative to the Municipal Departing Load tariff.”

¹⁵⁹ *Id.* at 135-137. CalCCA also cites AReM/DACC’s observation that each IOU has a “New Municipal Departing Load” tariff that includes the option to have the PCIA and other departing load obligations paid as a negotiated lump sum (Exhibit AD-1 at IV.C 27-28).

¹⁶⁰ CLECA opening brief at 18-19.

¹⁶¹ Commercial Energy opening brief at 36.

UC cites the prepayment option as the type of measured, ¹⁶²opt-in proposal that will allow for “gradual changes that can make improvements in a targeted way” to the PCIA framework. UC supports the AReM/DACC proposal because it is consistent with UC’s principle that there should be a clear end to a customer’s ongoing exit fee obligations: “a buyout option provides the most flexibility to the customer to determine the best course of action based on the risk and economic preferences of that customer.”¹⁶³

TURN strongly disagrees with permitting one-time prepayment “given the significant uncertainty associated with any forecast of long-term above-market costs.”¹⁶⁴ As TURN explains the issue,

Unless the resource commitments attributable to a departing load are terminated, bought out, or permanently resold, there is no way to guarantee that any prepayment calculation fairly reflects the actual above-market costs of the resources over an extended timeframe. Given the inability to demonstrate that a prepayment maintains indifference, the Commission should not permit this option to be implemented.¹⁶⁵

Finally, the Joint Utilities also oppose adoption of prepayment options for departing load customers. The Joint Utilities assert that “the record evidence convincingly demonstrates that requiring the Joint Utilities to accept a prepayment estimate of a customer’s long-term cost responsibility would shift substantial risks to remaining bundled service customers,” including:

¹⁶² Regents of the University of California opening brief at 5.

¹⁶³ *Id.* at 6.

¹⁶⁴ TURN reply brief at 35, citing Exhibit TURN-2 at 23.

¹⁶⁵ *Id.* at 36.

- forecast-related market risk (*i.e.*, the risks associated with forecasting costs and market values of the vintaged resources over a long-term period);
- volumetric risk (*i.e.*, the risks associated with forecasting the performance of the vintaged resources over a long-term period); and
- regulatory risk (*e.g.*, the risk of changes in regulatory rules that impact the forecasted costs, values, or performance of the vintaged resources over a long-term period).¹⁶⁶

We find that the record evidence cited by the Joint Utilities does not support their assertion that requiring them to accept a prepayment estimate of a customer's long-term cost responsibility would shift substantial risks to remaining bundled service customers. First, we do not intend to "require" the Joint Utilities to "accept a prepayment estimate"; our only requirement will be that they negotiate in good faith with their counterparties. Furthermore, AReM/DACC effectively rebutted the Joint Utilities' expressed concerns about forecast-related market risk, volumetric risk, and regulatory risk.¹⁶⁷ We also agree with Commercial Energy that prepayments will serve as a longer-term measure to reduce the size of the Joint Utilities' PCIA portfolios.

On this basis, we conclude that the solution that best fits the guiding principles articulated in the Scoping Memo is adoption of a prepayment option for departing customers.¹⁶⁸ The parties that best know the concerns and

¹⁶⁶ Joint Utilities opening brief at 87, citing Exhibit IOU-3 at page 7-16 through page 7-17.

¹⁶⁷ AReM/DACC opening brief at 34-35.

¹⁶⁸ See Guiding Principle 1.g, of course ("...allow an alternative provider to elect to pay for its share of above-market costs in a manner that complements the CCA's particular procurement needs and goals") as well as 1.b, 1.d., and 1.f.

priorities of departing load customers made convincing arguments that these customers--in particular among all utility customers--assign significant value to “certainty as to energy costs” (AReM/DACC) and “flexibility to the customer to determine the best course of action based on the risk and economic preferences of that customer” (University of California). Therefore, DA customers and CCAs, on behalf of their customers, shall be permitted to pre-pay their PCIA obligations, according to the specific terms proposed by AReM/DACC and listed above. As another means of mitigating any risks that may emerge as this provision is implemented, we will require that any prepayment arrangements shall be submitted to the Commission via a Tier 3 advice letter, so that we may review the arrangements on a case-by-case basis and deny approval to any agreements that do not reflect the balance we see here between the risks postulated by the Joint Utilities and TURN, on the one hand, and the concrete benefits to departing load customers described by their representatives, on the other.

6.2.5. Review of Other Proposals

In order to provide clear guidance to parties with respect to their future efforts in this proceeding, in this section we discuss our reasons for not adopting the proposals put forth by the Joint Utilities, AReM/DACC, CalCCA and Commercial Energy.

6.2.5.1. Joint Utilities

The Joint Utilities’ GAM/PMM proposal was strongly opposed by parties representing CCAs, Direct Access customers, ESPs, and consumer groups. CUE, which intervenes on behalf of the unionized workforce at the each of the Joint Utilities, opposed a central aspect of the GAM. Parties supporting the GAM/PMM included ORA and Brightline. Our conclusion that the GAM/PMM

should not be adopted is based on a number of findings and conclusions about its likely effects and its legality.

The Joint Utilities explain that under GAM, the RPS-eligible and large hydroelectric resources' benefits and costs are allocated to all customers in the following way:

- The Joint Utilities continue to manage the resources and make them available to the CAISO for dispatch;
- The market revenues (for energy, A/S, and any other revenues) are then assigned pro rata to all benefitting customers as an offset to the costs of those resources; and
- The RA and REC attributes of those resources are allocated pro rata to the LSEs serving departing load customers.

As part of their proposal in this proceeding, the Joint Utilities request that the Commission clarify the following regarding D.11-12-052:

- Under the guidelines set forth in D.11-12-052 regarding PCC criteria, the allocation of PCC 1 RECs under the GAM proposal does not alter their PCC 1 classification because:
 - The GAM process does not separate the RECs from the RPS-eligible energy with which they were originally associated; and
 - The allocation under GAM is not a "re-sale" of RECs.
- Nothing in the decision addresses the narrow circumstance before the Commission in this proceeding--namely, the allocation of RECs to customers upon whose behalf RPS-eligible procurement was undertaken, and who later departed bundled service to be served by a CCA/DA provider.
- Nothing in the decision interferes with the conclusion that the allocated PCC 1 RECs received by customers upon whose behalf RPS-eligible procurement was undertaken, and who later departed bundled service to be served by a CCA/DA provider, retain their PCC 1 classification.

The Joint Utilities clarify that they do not assert that D.11-12-052 requires modification: “nothing in the decision prevents a finding in the instant case that RECs allocated pursuant to a Commission-approved GAM mechanism retain their PCC 1 classification.” Rather, the Joint Utilities are requesting a “clarification or interpretation” of D.11-12-052, by means of a Commission finding in the instant case that “RECs transferred to departing load customers, on whose behalf RPS procurement was originally undertaken, pursuant to the GAM mechanisms do not, by virtue of that allocation, lose their PCC 1 classification or become ‘unbundled RECs’ as that term is used in Section 399.16(b)(3) and in D.11-12-052.

ORA supports the Joint Utilities’ proposal, reasoning that while “It would be ideal for IOUs to make a complete transfer of the energy with the renewable energy credit (REC) and RA attributes, but the next best option is to preserve the more valuable long-term REC attribute.”¹⁶⁹ Brightline agrees with the Joint IOUs that their proposed allocation methodology would not separate the RECs from the underlying electricity with which they were originally associated.¹⁷⁰

The Joint Utilities’ proposal and request for Commission clarification are opposed by CalCCA, CUE, POC, the Regents of UC, Solana Energy Alliance and, most thoroughly, TURN.¹⁷¹

¹⁶⁹ ORA reply brief at 2-3.

¹⁷⁰ Brightline reply brief at 6.

¹⁷¹ See, CalCCA reply brief at 17, CUE opening brief at 19-21, POC reply brief at 11-12, the Regents of UC reply brief at 5-6, Solana Energy Alliance reply brief at 2-6 and TURN opening brief at 17-25 and reply brief at 24-29.

The Joint Utilities' interpretation of Section 399.16(b)(3) and D.11-12-052 is incorrect. First, as TURN explains, the Joint Utilities' suggestion that we view their proposed transactions as identical to a "forward sale of bundled renewable energy that satisfies the PCC 1 requirements" fails because the LSE receiving the allocation does not actually receive any energy to serve its customers – that energy is retained by the IOU. As TURN observes, "this arrangement therefore fails to satisfy the requirement that any PCC 1 resale transaction must result in electricity being 'transferred to the ultimate buyer in real time,' and in reality "functionally replicates the sale of an unbundled REC rather than the sale of bundled renewable energy described in D.11-12-052."¹⁷²

We also agree with TURN's practical objections to the Joint Utilities' proposal:

As explained in TURN's opening brief, the GAM allocates unbundled attributes that are not accompanied by the associated energy needed for LSEs to serve their retail customers. This approach severely complicates LSE procurement planning, alters the anticipated impacts of the RPS program, may lead to greater reliance on short-term procurement of unspecified energy, does not comport with state disclosure and reporting requirements, and could create significant customer confusion.¹⁷³

TURN also rebuts the Joint Utilities' assertion that the "only way to optimize the value of the existing RPS resources, avoid double procurement, and achieve equitable cost allocation" is to adopt the GAM proposal:

¹⁷² TURN reply brief at 26, citing D.11-12-052 at 55.

¹⁷³ *Id.* at 27-28.

The allocation of the unbundled RPS attributes to other LSEs through GAM does not create value that would otherwise be unrealized. By declining to engage in forward sales of bundled renewable energy products, the IOUs would be limited to realizing CAISO hourly market prices for the renewable energy output and valuing the RPS product at that market price. TURN believes that higher prices may be obtained through forward sales (via auction or solicitation) or by having other LSEs subscribe to a pro rata fraction of the portfolio and pay the embedded cost of the underlying resources. The IOU proposal is self-defeating because it forecloses the opportunity to sell these products at anything but the CAISO market prices.

Moreover, the transfer of unbundled renewable energy attributes will not assist most LSEs to serve their customers but will create reporting and disclosure challenges. As pointed out in TURN's opening brief, the GAM does not avoid double procurement because each LSE receiving the renewable energy attributes would procure separate unrelated physical resources to serve customer loads. Adopting the GAM would either encourage LSEs to rely heavily on short-term purchases of unspecified power or cause LSEs to engage in the procurement of specified resources that would effectively ignore the allocated attributes.

Either outcome is suboptimal and avoidable.¹⁷⁴

Beyond these specific objections to the Joint Utilities' GAM proposal with respect to renewables, a number of parties contend that the GAM is contrary to law because it "invades the procurement function reserved for CCA

¹⁷⁴ *Id.* at 28-29.

programs.”¹⁷⁵ This brings us back to the statutory framework we outlined at the beginning of this decision and provides an appropriate point of conclusion.

Solana Energy Alliance notes that the Joint Utilities rely on language in Public Utilities Code section 366.2(g) as a legal basis for the GAM. Section 366.2 was created by AB 117 and governs CCA formation. In its entirety, Section 366.2(g) provides that

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

The Joint Utilities deconstruct this language in order to suggest that

Because RA and REC attributes are allocated to departing load customers, GAM/PMM is also completely consistent with Section 366.2(g), which contemplates the “allocate[tion of] a fair and equitable share of [the] benefits” of the historical IOU procurement.¹⁷⁶

Solana responds that:

As a whole, the statute provides a mechanism for bundled customers to recover costs from CCA customers, and while it recognizes that benefits may be allocated to CCA programs, such allocations are to be taken into consideration for cost recovery purposes. The statute does not provide an independent legal basis for the allocation of RECs or other

¹⁷⁵ Solana Energy Alliance reply brief at 1.

¹⁷⁶ Joint Utility opening brief at 44.

resource attributes to CCA programs. The legislature would have to take further action to do that.¹⁷⁷

Solana further argues that:

The interpretation that the Joint IOUs advance would also directly conflict with Public Utilities Code section 366.2(a)(5), which specifically provides that CCA programs shall be "solely responsible" for procurement on behalf of their customers. Under the GAM proposal, the Joint IOUs would procure on behalf of CCA customers and allocate critical resource attributes – RECs--to them.⁷ An interpretation of Public Utilities Code section 366.2(g) that permits such an outcome would invade the procurement function reserved for CCA programs. The rules of statutory interpretation require a different reading of the statute than what the Joint IOUs are proposing. As a result, the statute does not provide a legal basis for allocating RECs under the GAM proposal.¹⁷⁸

6.2.5.2. CalCCA

As is evident throughout this decision, we find CalCCA's analysis of the challenges facing the utilities, departing load interests, other stakeholders, and this Commission to be very thoughtful and well informed. However, we do not find that CalCCA has demonstrated that, if we were to adopt their proposed revisions to what would still be "administrative" benchmarks, greater accuracy would result. We believe that our adopted approach, using the best available transactions data to approximate a realistic PCIA obligation, followed by a true-up, will be more effective in stabilizing cost recovery while longer-term solutions

¹⁷⁷ Solana Energy Alliance reply brief at 2.

¹⁷⁸ *Id.* at 3-4, citing Joint Utility opening brief at 42-44.

are developed in and implemented. It is in that effort that we believe CalCCA's ideas and approach to these challenges will have the greatest contribution.

7. Phase 2 of this Proceeding: Portfolio Optimization and Cost Reduction

In this section of the decision we address Issues 5, 6 and 7 from the Scoping Memo:

5. Should the Commission require and verify optimization of IOU portfolio management (*e.g.*, contract extensions and contract renegotiation) in order to minimize above-market costs?
6. Should the Commission adopt alternatives to the PCIA framework, including but not limited to the following?
 - b. Portfolio buy-out by CCA/ESP; and
 - c. Assignment of IOUs' contracts to CCA/ESP.
7. Should the Commission require forecasting of the PCIA or an alternative cost allocation method for a specific future period?

As discussed below, we find that a second phase should be opened in this proceeding in order to establish a "working group" process to enable parties to further develop a number of proposals regarding portfolio optimization and cost reduction for future consideration by the Commission.

7.1. General observations

ACC notes that the utilities are already undertaking various actions to optimize their portfolios through the sale of certain resources. In the longer-term, the Commission should continue to consider other options for optimizing the utilities' portfolios.

AReM/DACC asserts that IOU portfolio optimization is clearly necessary, given the significant over-supply situation that affects each IOU, and recommends that this immediate proceeding does not address the issue, it

should be addressed as soon as possible in a new phase. Regardless, “the Commission must continue to provide specific direction to the IOUs to minimize the stranded costs by actively managing their PPA portfolio, including and especially taking steps to minimize customer costs and exposure to higher-prices PPAs.”¹⁷⁹

CalCCA recommends that the Commission 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, CalCCA contends that this would reduce portfolio costs by \$496 million for PG&E and \$131 million for SCE. Over the 20-year term of a securitization bond issuance, CalCCA estimates total benefits with a net present value of \$1.3 billion for PG&E and \$589 million for SCE.

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, including:

- 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.

¹⁷⁹ AReM/DACC opening brief at 30.

CLECA recommends use of a working group to develop its recommended pilot auction process and to set a timeline of regular auctions to align with the RA timeline and with required notices. Similarly, a working group or Energy Division staff or an Independent Evaluator could be used to engage in the empirical exercise of determining a subset of RPS contracts for possible allocation, and also for possible securitization.

The City of San Diego recommends that the Commission institute new phases of this proceeding to further define and develop promising longer-term solutions to reduce the portfolio costs: “deferring them to future yet-defined rulemakings or applications risk a loss of momentum.”¹⁸⁰ San Diego agrees with the Joint Utilities that a formal working group of stakeholders should be established for this purpose.

CSD believes that the Commission should establish new phases to this proceeding to allow for a more in-depth assessment of the different elements proposed by parties. At the same time, CSD is mindful that there is a need to continue with the determination of an updated PCIA methodology. Therefore, CSD recommends parallel phases to this proceeding to examine the following:

- Long-term measures to reduce the PCIA (*e.g.*, securitization, contract buydowns); and
- Valuation of assets remaining in the Joint Utilities' portfolios (*e.g.*, auction mechanisms such as that proposed by Commercial Energy and CalCCA including timing, content, degree, and market integrity protection measures of such auctions)

¹⁸⁰ City of San Diego opening brief at 10-11.

Rather than establishing panels to address these issues, all stakeholders should have an opportunity to participate in these activities. CSD recommends that these activities be overseen and pushed forward by an Assigned ALJ (preferably) or by the Energy Division. Without some form of accountability, CSD is concerned that the discussions will fail to work toward development of solutions.

IEP notes that some proposals made in the context of optimizing the IOUs' portfolio have suggested that the Commission consider tools to minimize above-market costs subject to PCIA treatment, including contract modifications or renegotiation and contract assignment. IEP cautions that the Commission must respect the sanctity of existing contracts because undermining the sanctity of existing contracts risks litigation, undermines the perception of the sanctity of future contracts approved by the Commission, and thereby undermines a critical mechanism for the state to foster investment in the infrastructure needed to achieve public policy goals in a timely, cost-effective manner.¹⁸¹

The Joint Utilities adopt a cautious posture in their discussion of "portfolio optimization and cost reduction," generally asserting that while some proposals of other parties raise significant issues that would need to be considered in other proceedings (*e.g.*, CalCCA's securitization proposal). The Joint Utilities largely view their GAM/PMM proposal as a sufficient solution to the challenges raised by others. Despite our determination in this decision to adopt a different

¹⁸¹ IEP observes that "bilateral contracting, particularly long-term contracting, is a key foundation upon which the Commission's market model relies." IEP opening brief at 2, citing, generally, D.10-06-018.

approach, we will continue to look to the Joint Utilities to participate with enthusiasm and creativity in the next phase of this proceeding.

ORA reiterates its recommendation from its testimony that any PCIA charge or alternative ultimately adopted must be flexible enough to be able to “coexist with cost-reduction strategies and inter-party agreements.”¹⁸²

POC observes that the Joint Utilities recommend that the Commission defer consideration of portfolio optimization proposals and, as a general matter, appear to take the position that their current portfolio management efforts are adequate to achieve alignment of their resource portfolios and bundled customer needs. To the contrary, POC asserts that “new optimization incentives and requirements are necessary to achieve the final guiding principles set forth by the Commission, including that the PCIA only include legitimately unavoidable costs.”¹⁸³

POC therefore supports recommendations by parties that would minimize above-market costs, including portfolio buydown, securitization of UOG, requiring improved risk mitigation in departing load forecasting, and modifying departing load vintages in response to utility portfolio management decisions. POC adds that “the Commission should ensure that existing portfolio optimization mechanisms are providing the intended checks on procurement activities:”

The Joint Utilities cite Independent Evaluator (IE) review and the Procurement Review Group (PRG) as two key oversight mechanisms “to ensure fairness among potential counterparties and transparency of individual transactions.”¹³⁵ Yet the Joint

¹⁸² ORA opening brief at 15, citing Exhibit ORA-1 at 9.

¹⁸³ POC opening brief at 27.

Utilities fail to show that the PRG and IE are accomplishing these objectives, and the record suggests they are not.

POC recommends that the Commission act to ensure the independence of the Independent Evaluator, and replace the existing Procurement Review Groups with public scrutiny.

Shell Energy recommends that in this decision the Commission endorse parties' recommended optimization approaches to reduce the IOUs' portfolio costs and allow non-IOU LSEs to voluntarily acquire a portion of an IOU's portfolio. The Commission should also establish a new phase of this proceeding in order to address the implementation details of the adopted measure(s), e.g., an auction process, an IOU procurement contract renegotiation process, and/or a procedure for securitizing IOU UOG assets.

Solana Energy Alliance urges the Commission to recognize the problem of excess supply, acknowledge the need to provide for an auction or other transfer mechanism, and take steps toward establishing a process that would resolve the excess supply problem:

While securitization and other proposals have merit and may be effective in reducing costs, there is a fundamental problem emerging that must be addressed in the near future: excess supply. Given the magnitude of departing load that is anticipated, both IOUs and CCA programs will be procuring for the same customers, and excess power supply may result, at great cost to retail customers.

This scenario is avoidable, but it may require a mechanism by which Power Purchase Agreements and other contracts held by the IOUs can be auctioned, sold or otherwise transferred to CCA programs and potentially DA providers in return for fair compensation. Establishing such a mechanism may require

that additional steps be taken, but at least from SEA's perspective, the need exists.¹⁸⁴

TURN refers back to its core proposal to reform the PCIA and add a true-up, and then asserts that:

The adoption of a true-up does not exempt utilities from their obligation to prudently manage their resource portfolios and achieve maximum value for all ratepayers. The Commission should not relieve utility shareholders of the financial consequences of inappropriately withholding valuable assets from willing buyers, imprudently operating their utility owned generation, mismanaging their power purchase contracts, or unreasonably transacting in wholesale markets. Furthermore, the Commission could establish other metrics for reasonable portfolio management in connection with the allocation, sale and auction proposals that may be adopted in this proceeding.¹⁸⁵

TURN concludes that the Commission should recognize that new approaches are necessary to monetize the key attributes in the utility portfolios and avoid stranding the portfolios' environmental and economic value. TURN supports exploring innovative approaches so long as they comport with existing law, do not open new loopholes that could undermine resource planning objectives, and are implementable within a reasonable time frame. TURN offers the following specific recommendations:

- Consider TURN's three alternative portfolio allocation proposals that would promote greater forward sales of utility resources, permit LSEs to voluntarily subscribe to some or all of the IOU resource portfolio, and encourage the IOUs to conduct auctions for existing resources.

¹⁸⁴ Opening brief of Solana Energy Alliance at 11.

¹⁸⁵ TURN opening brief at

- Initiate a subsequent phase of this proceeding that may be consolidated with other relevant dockets to consider key issues relating to the implementation of a short list of preferred portfolio allocation proposals submitted by TURN and other parties.
- The Commission should endorse further consideration of securitizing UOG ratebase investments and contract buydowns that benefit all ratepayers. This endorsement should include a request to the Legislature for prompt action to enact the key statutory provisions needed to allow securitization to proceed.

UCAN supports TURN's view that Retail Sellers should be provided options for participating in and possibly managing a portion of the IOUs' portfolios of relevant resources, and also receive a related reduction or elimination of related PCIA charges.¹⁸⁶ UCAN also supports Commercial Energy's VAAC proposal to allow CCAs and ESPs to have rights to use and to value contracts for which they choose to be responsible.

7.2. Forecasting

Brightline generally agrees that the IOUs need to make reasonable efforts to forecast departing load but also recognizes that requiring IOUs to under-procure may violate the statutory directive that mandates the IOUs to procure energy on behalf of all customers in their territory until customers have actually departed. The Commission should provide guidance on how to determine what constitutes a reasonable forecast of departure and whether IOUs should stop procuring on behalf of a customer when a CCA's application has been fully approved or wait until the CCA actually begins serving customers.

¹⁸⁶ UCAN opening brief at 32, citing its own rebuttal testimony (Exhibit UCAN-02) and Exhibit TURN-01 at 2.

CalCCA recommends that the Commission should direct the Joint Utilities to modify their forecasting practices to better account for departing load and require the utilities to formalize the approach used in this rulemaking for long-term PCIA forecasting in ERRA proceedings.¹⁸⁷

IEP responds to CalCCA's proposal that the Commission require "risk mitigation in departing load forecasting" by employing a more expansive review of portfolio costs to reduce "stranded cost risk" associated with the PCIA-eligible procurement. IEP describes the CEC's biennial Integrated Energy Policy Report (IEPR) and the Commission's Integrated Resource Planning (IRP) proceeding and suggests that given this "rigorous planning and modeling" the Commission should question the added value of and necessity for an additional forum for assessing forecast demand and departing load.¹⁸⁸

Commercial Energy labels its suggestion in this area "cost responsibility forecasting" and recommends that, whatever mechanism the Commission adopts, the IOUs should be required to make public their forecasts of the anticipated cost responsibility to be included in rates of departing load customers, by customer class. Depending on the adopted mechanism, this requirement would apply on an annual or quarterly basis.¹⁸⁹

The Joint Utilities note that their proposal in this proceeding includes a standardized forecasting methodology that can be used with any of the cost allocation methods proposed this proceeding. They assert that their methodology maximizes the use of public data, "while maintaining

¹⁸⁷ CalCCA opening brief at 97 and 142-144, respectively.

¹⁸⁸ IEP opening brief at 4.

¹⁸⁹ Commercial Energy opening brief at 37.

confidentiality protections necessary to both shield remaining bundled service customers from the potential harm caused by disclosure of bundled service customers' market-sensitive procurement information to other market participants, and to protect the integrity of California's competitive energy markets."¹⁹⁰ The Joint Utilities state that their methodology was developed in accordance with the following principles:

- Data should be provided in a manner that will allow each LSE to develop an annual forecast based on its own expectations of market prices;
- Data must be provided in a manner that complies with Section 454.5(g) and the Commission's confidentiality rules;
- Public data should be used to the greatest extent possible; and
- If confidential data are required, such data should be aggregated.¹⁹¹

7.3. Optimization

As part of portfolio optimization, AReM/DACC believes the IOUs must take proactive steps to mitigate their long positions created by the expansion of CCAs and reduce the stranded costs associated with out-of-market PPAs. AReM/DACC notes that the IOUs have taken steps, "albeit baby ones," in this regard. AReM/DACC cites Guiding Principle 1.h. (any PCIA methodology "should only include legitimately unavoidable costs and account for the IOUs' responsibility to prudently manage their generation portfolio and take all reasonable steps to minimize above-market costs.") and suggests

¹⁹⁰ Joint Utilities opening brief at 80-81.

¹⁹¹ *Id.* at 81.

In that regard, the CalCCA witnesses make several salient observations and recommendations on needed going forward IOU procurement reform to reduce stranded costs, such as:

- “A utility's obligation does not stop with a single procurement decision, based on the best information available at the time, but involves many subsequent decisions regarding the ongoing portfolio composition based on new information regarding market developments and changes in demand.” Ex. CalCCA-01, at 2A-5.
- “The existence of a resource in the utility portfolio - even if the initial decision to procure it was prudent given the information available at that time - does not alleviate the utility of their responsibility to actively manage those resources to the benefit of all customers.” *Id.*
- “Following least cost dispatch for must-take generation with near zero operating costs does not qualify as prudent management - that is simply housekeeping.” *Id.*, at 2A-760.

CalCCA recommends that the Commission direct the Joint Utilities to improve portfolio management practices, as follows:

1. Require the Joint Utilities to actively manage their portfolios in response to departing load;
2. Prohibit the Joint Utilities' practices aimed to protect shareholders and bundled ratepayers at departing load customers' expense; and
3. Require the Joint Utilities to optimize sales from their portfolios to capture the full value of the resources for all customers.

Commercial Energy supports optimization of the IOU PCIA portfolios and believes the Commission should adopt a range of portfolio management measures that can be implemented in the near- term and over a longer timeline.

The City of San Diego agrees with various non-IOU parties regarding the need for valuation of all attributes of the various elements of a utility's portfolio

in order to properly determine the net costs associated with customer departure. However, the City echoes testimony by other parties that if the Commission were to establish a market-based process to establish the value of those attributes, it must ensure that the process cannot be manipulated by market participants, and this will require more time than is available in this phase of this proceeding.

UC supports the creation of a separate track in this proceeding focused on the implementation of IOU portfolio optimization.

7.4. Securitization

AReM/DACC note that securitization effectively lowers the revenue requirement associated with the assets or PPAs by reducing financing costs. It does so by replacing higher yielding financing such as stock equity with very low yield, low risk bond financing. However, this approach does tend to shift more of the risk of asset or PPA failure from IOU shareholders to ratepayers as the guarantors of the securitization. The ratepayers are at risk because the bond payments would be included in rates. Given the potential benefits of securitization to both bundled and departed ratepayers, AReM/DACC recommend that the Commission approve the concept of moving forward with securitization, with a follow-on proceeding to explore all of the issues needed to be determined prior to implementation.¹⁹²

CalCCA recommends that the Commission direct the utilities to use their best efforts to reduce portfolio costs using securitization of UOG assets and contract buydown transactions. Under CalCCA's proposal, remaining IOU ratebase in UOG assets would be refinanced via securitized debt backed by a durable and nonbypassable rate recovery mechanism.

¹⁹² AReM/DACC opening brief at 32-33.

Commercial Energy agrees that securitization of UOG could be a useful tool to reduce the IOUs' over-procured PCIA portfolios in the long term. However, Commercial also notes that securitization will require legislation and, if successful, will involve lengthy negotiations and Commission approval.

CUE agrees that securitization might be useful tool in the future to reduce portfolio costs, but emphasizes that it does not resolve the cost shifting problem now.

CLECA recommends seeking and supporting legislation to allow for securitization, and then engaging in efforts to securitize a subset of the high-priced RPS contracts.¹⁹³ However, CLECA also agrees with the Joint Utilities that there are many potential uses for securitization, and that securitization has limits.

The City of San Diego notes that CalCCA testimony related to securitization did not address its proposal as it relates to SDG&E, so Commission does not have meaningful record evidence to support a conclusion to order securitization by SDG&E. For that reason, the City supports the Joint Utilities' recommendation to examine securitization in the future.

The Joint IOUs recommend that CalCCA's securitization proposal be considered outside this proceeding.

ORA recommends that the Commission establish a working group to analyze the securitization approach "to determine whether it is compatible with California's electricity market, whether there are any entities that would be interested in holding such a bond, and whether there may be any unexpected

¹⁹³ CLECA opening brief at 27. CLECA suggests focusing on the subset of those contracts that would have the most impact, as opposed to contracts with Department of Energy loan guarantees that are unlikely to benefit from securitization since they already have low-cost debt.

consequences associated with undertaking this new process.” ORA states that there may be value in the strategy to pay down the IOUs' investment in generation rate base.

TURN addresses CalCCA's securitization proposal and raises several practical concerns. Nevertheless, TURN believes that this strategy merits further consideration and prompt action, given the potentially significant ratepayer savings. TURN recommends that the Commission endorse the concept and urge Legislative action in the current session, and offers its assistance in that task.¹⁹⁴

UCAN recommends securitization of all utility assets that have a remaining life of more than 5 years. UCAN asserts that the IOUs have not prudently managed their generation portfolio to minimize above-market costs:

The lack of portfolio cost control, the [Joint Utilities'] indifference to downward cost trajectories for solar PV and wind, and the lack of portfolio optimization each suggests that all customers, bundled and departing load alike, should be absolved of some of the responsibility for IOU imprudence and negligence in managing PPAs.

7.5. Buydown/buyout

ACC agrees that discussions with counterparties to "buy down" contracts may lead to contract structures that are mutually beneficial for both counterparties, but cautions that any such discussions must respect the rights of parties to those contracts to accept or reject a utility's buy-down proposal. ACC cites Guiding Principle "k," which states that for this proceeding any PCIA

¹⁹⁴ TURN opening brief at 31-33. TURN details its concerns regarding (1) matching cost recovery periods with the term of new debt, (2) ongoing IOU accountability for managing their UOG assets, and (3) the Commission's authority to direct such financing without express enabling legislation. Nevertheless, TURN does not consider these concerns to be insurmountable.

Reforms “should respect the terms of existing power purchase agreements between power suppliers and IOUs.”

Commercial Energy agrees that PPA buy-out or buy-down efforts could be a useful means of reducing the IOUs’ PCIA portfolios. Because of the significant time that would be required to renegotiate the existing PPAs or to provide buy-down funds through securitization, however, Commercial believes that the Commission should treat these options as long-term solutions to the IOUs’ portfolio issues.

ORA is skeptical of utilizing a securitized bond to “buy down” the IOUs’ contracts, listing a number of concerns in its opening brief.¹⁹⁵

TURN does not oppose the use of buydowns or buyouts to reduce net procurement costs for all customers, but notes that its witness testified that the benefits “may not be significant” and explained why the reduction in costs could prove to be relatively minor. Thus, TURN cautions the Commission against investing substantial amounts of effort on such a process.¹⁹⁶

7.6. Discussion

This proceeding took on an ambitious scope of issues, and covered a lot of ground in a relatively short period of time. We are impressed that in the end, parties have reached a general procedural consensus in favor of quick but incremental action in the short term, coupled with a willingness to initiate a new phase of this proceeding so that they may continue to work together in an effort to achieve successful outcomes in the challenging areas of portfolio optimization and cost reduction.

¹⁹⁵ ORA opening brief at 14-15.

¹⁹⁶ TURN opening brief at 30-31.

For these reasons, we find that a second phase should be opened in this proceeding in order to establish a “working group” process to enable parties to further develop a number of proposals regarding portfolio optimization and cost reduction for future consideration by the Commission. This decision directs that a prehearing conference be scheduled to initiate that process.

8. Other Issues

Parties raised several additional issues outside of the topics addressed above. We discuss each issue below.

8.1. Tariffs and Bill Presentation

AReM/DACC proposes that the Commission eliminate the CRS tariffs and make the PCIA a stand-alone tariff. AReM/DACC explains that all three IOUs present their PCIA rates on their tariffs differently from one another and observes that this is awkward and unnecessary.¹⁹⁷ AReM/DACC recommends that, in addition to updating and re-naming the CRS tariffs, all three IOUs place all the specific PCIA rates in a new PCIA tariff, rather than simply describing the component and burying the actual rates deep in the individual rate schedules.¹⁹⁸

The Joint Utilities do not object to AReM/DACC’s recommendation and concur that it would be beneficial if the PCIA or its successor charge were more transparent and easier for customers to find in the IOUs’ respective tariffs. That said, the Joint Utilities contend that before the proposal can be implemented, issues such as identifying the necessary substantive changes and conducting customer outreach will need to be addressed.¹⁹⁹

¹⁹⁷ Exhibit AD-1 at 34.

¹⁹⁸ *Ibid.*

¹⁹⁹ Exhibit IOU-3 at page 7-15.

CalCCA proposes that the Commission 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. In contrast, PG&E currently separately identifies the PCIA rate 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. CalCCA notes that "the current utility bill presentation masks the fact that all customers are shouldering the burden of the utility's uneconomic costs," and "without explanation, customers might erroneously conclude that CCA customers are required to pay additional costs not included in bundled service." CalCCA recommends that the Commission 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.

In response to CalCCA, the Joint Utilities state that although they support greater rate and bill transparency, the Commission should not require them to implement this proposal at this time. Rather, the Commission should hold one or more workshops in 2019 to identify the impacts of this change on existing GRC Phase 2 settlements and the Joint Utilities' tariffs and billing systems, so that a more informed and thoughtful approach can be taken to providing all customers greater rate and bill transparency on the PCIA or any successor rate(s).

CalCCA responds to the Joint Utilities and agrees that their proposed workshop process could be a useful vehicle for accomplishing its proposed changes, but suggests that the Commission set a deadline for implementation.

CLECA also reports that it supports greater transparency, but agrees with the Joint Utilities that the Commission should consider such changes in

connection with General Rate Cases: the Commission should defer the billing issues to the General Rate Cases and direct the utilities to propose more transparent billing formats in their next Phase 2 proceedings.²⁰⁰

We find merit in the tariff revision and bill presentation proposals put forth by AReM/DACC and CalCCA. We agree that bundled customers should be made aware of the fact that all customers are paying their share of the utility's uneconomic costs. Clearly, changes to bills are necessary, and we are not persuaded by arguments by the Joint Utilities and CLECA that such changes will have impacts on existing GRC Phase 2 settlements. Nevertheless, we find that the workshop process proposed by the Joint Utilities and endorsed by CalCCA is a reasonable means of working out the details regarding how and when to introduce the changes to the bills, and to the tariffs, as AReM/DACC recommends. The workshop logistics, and the deadline for a proposal from the Joint Utilities and interested stakeholders, should be discussed early in the next phase of this Rulemaking.

8.2. Remaining Issues

EPUC limits its input to a single issue, explaining why the Commission should retain its existing treatment of cogeneration customer generation departing load (CGDL).²⁰¹ We are unaware of any such proposal in this proceeding, and we affirm that we leave existing treatment of CGDL undisturbed in this decision.

²⁰⁰ CLECA opening brief at

²⁰¹ Opening brief of the Energy Producers and Users Coalition at 1-3.

9. Implementation

9.1. Calculation of the Revised PCIA

On June 6, 2018 the assigned ALJ directed parties to address the mechanics of implementing their proposals in their reply briefs, and allowed parties to respond to other parties on this topic in supplemental briefs to be filed and served on June 25, 2018. Supplemental briefs were submitted by AReM/DACC, CalCCA, CE, and the Joint IOUs. The discussion below reflects that input and summarizes the steps that shall be followed in order to calculate the PCIA in compliance with this decision.

The Commission's Energy Division shall calculate the following values: (1) the brown power index, (2) the RPS Adder, and (3) the RA adder. The resulting values shall be made available to interested parties at the beginning of November each year, and shall be used by PG&E, SCE and SDG&E to calculate the PCIA that takes effect January 1 of the following year.

First, the brown power index shall continue to be calculated using the methodology adopted in D.06-07-030.

Second, the RPS Adder shall be calculated using reported prices from purchases and sales of renewable energy by the IOUs, CCAs and ESPs during the year that is two years prior to the forecast year (year n-2) for delivery in the forecast year (year n). For the 2019 RPS Adder only, the Energy Division shall use the LSE cost information submitted on August 20, 2018 in their 2019 RPS Procurement Plans.

Third, the RA Adder shall be calculated using reported purchase and sales prices from IOU, CCA, and ESP transactions made during (year n-2 and year n-1) for deliveries in (year n-1 and year n). A zero or *de minimis* price shall be assigned for capacity expected to remain unsold. The RA Adder shall be

calculated in a manner that reflects the three types of RA capacity: system, local, and flexible. For the 2019 RA Adder only, the Energy Division shall use the weighted average system and local RA prices in the most recent annual RA report.

9.2. Rate Design

In their opening testimony, the Joint Utilities explained that under current ratemaking practices, vintaged Indifference Amounts determined using the Current Methodology are allocated to rate groups using a “Top 100 hours” methodology that is based on the contribution of each rate group to the highest 100 hours of system load. The allocated costs are then divided by the rate group’s total forecast system sales to determine the Indifference Rate for that vintaged portfolio. The Joint Utilities recommended changing the revenue allocation factors for vintaged Indifference Amounts to be consistent with the factors used to allocate generation costs to their bundled service customers: both bundled service and departing load customers are paying the same costs but the disparity caused by using two different types of allocation factors results in higher rates for departing load residential customers relative to their bundled service counterparts, and lower rates for other departing load customer classes relative to their bundled service counterparts. According to the Joint Utilities, “the simple solution of using consistent allocation factors for both groups avoids further distortion in customer indifference for residential customers and is easily implemented.”²⁰²

Several parties opposed the Joint Utilities’ proposal. CLECA states that it understands the concern that these costs be allocated in a similar way to

²⁰² Exhibit IOU-1 at page 4-65.

customers regardless of their LSE, but asserts that “this is not a trivial change and is being proposed in this rulemaking, rather than in a GRC Phase 2 where cost allocation changes are generally made.”²⁰³ Commercial Energy opposes the proposed change for the reasons identified by CLECA, agreeing that “this issue has impacts beyond this proceeding, and involves parties who are not concerned with the PCIA methodology.”

On May 8, 2018 the Joint Utilities presented a joint stipulation for waiver of cross examination by CLECA, subsequently marked and received into evidence as Exhibit IOU-CLECA-1. In that exhibit, the Joint Utilities stipulated to a number of “statements of fact” in exchange for CLECA’s waiver of most of its estimated cross examination of Joint Utility witnesses. The statements of fact included the following:

Referring to the Joint Utilities’ rebuttal testimony at 7-14 (as well as 1-5, lines 21-27) footnote 34 references what is properly addressed in GRC Phase 2 cases, and that bill changes for transparency purposes may implicate Phase 2 settlements; the Joint Utilities stipulate that the following matters are properly addressed in GRC Phase 2s:

- a. Marginal costs;
- b. Revenue allocation, including application of various allocation methodologies and allocation factors (such as top 100 hours) to rate/customer classes of generation revenues, distribution revenues, etc.; and
- c. Rate Design.²⁰⁴

²⁰³ Exhibit CLECA-1 at 26.

²⁰⁴ Exhibit IOU-CLECA-1 at 3, statement of fact number 8.

We do not find the objections to the Joint Utilities' original proposal convincing. We note that even CLECA acknowledges concern that these costs be allocated in a similar way to customers regardless of their LSE. We also disagree that this change, in particular, is better left to GRC Phase 2 proceedings. Those proceedings are utility-specific, whereas this change is warranted for each of the Joint Utilities. Furthermore, the relevant proceedings that could include a new proposal such as this one have yet to be initiated and will be initiated once per year, over a three-year period. Finally, utility rate design proceedings are often resolved through "black box settlements" that the parties decline to explain in any detail to the Commission, so we have no guarantee that a reasonable proposal such as this one would even be agreed to by parties in those proceedings. For all of these reasons, we find that the proposal made by the Joint Utilities in Exhibit IOU-1 should be adopted in this decision, so that the revenue allocation factors for vintaged Indifference Amounts are consistent with the factors used to allocate generation costs to the Joint Utilities' bundled service customers. Each of the Joint Utilities shall implement this modification in the advice letters that they file to implement the other ratemaking changes adopted in this decision.

9.3. Annual True-up

Today, revenues collected from departing load customers via the PCIA rate are credited to the ERRRA balancing account. Although we do not adopt the Joint Utilities' GAM/PMM proposal in this decision, we find that the ratemaking proposal made in Exhibit IOU-1 provides general concepts that we can use to implement the annual true-up process that we adopt in this decision.

We direct PG&E, SCE and SDG&E to each establish a Portfolio Allocation Balancing Account (PABA) with three subaccounts to account for the costs and

revenues associated with the brown power index, the RPS Adder and the RA Adder. Each utility shall also modify its ERRRA balancing account and any other balancing accounts, as necessary, to be consistent the PABA structure adopted in this decision. Any year-end undercollection or overcollection in the PABA shall be incorporated into the PCIA rate calculation in the following year, as part of each utility's ERRRA forecast proceeding. The accuracy of the entries in the PABA and its subaccounts shall be reviewed in each utility's annual ERRRA compliance proceeding.

10. Conclusion: The Guiding Principles

We conclude this decision by reviewing our determinations in light of the guiding principles adopted in the Scoping Memo at the outset of this proceeding.

The adopted guiding principles provided that "any PCIA methodology adopted by the Commission to prevent cost increases for either bundled or departing load" should be consistent with each of the principles listed below, and we address each in turn:

- a. 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;**

We find that this principle is satisfied because the revised PCIA will still be calculated in each utility's ERRRA forecast proceeding, albeit with procedural modifications that we have directed be developed by parties in the second phase of this proceeding.

- b. Should have reasonably predictable outcomes that promote certainty and stability for all customers within a reasonable planning horizon;**

We find that this principle is satisfied because we have adopted an annual true-up, a provision to cap the PCIA

rate if necessary, and the option for departing load customers to pre-pay their PCIA obligation.

- c. Should be flexible enough to maintain its accuracy and stability if the number of departing customers changes significantly, and to maintain its accuracy and stability if customers return to bundled-customer service;**

We find that this principle is satisfied because we are maintaining the current calculation methodology and utility ratemaking accounting mechanisms, which have shown no signs of an inability to handle differing volumes of departing load activity.

We have also determined that a second phase of this proceeding should be opened in order to pursue solutions to the challenges of portfolio optimization and cost reductions, which will provide an ongoing opportunity to propose additional means of fulfilling this guiding principal.

- d. Should not create unreasonable obstacles for customers of non-IOU energy providers;**

We find that this principle is satisfied because we are establishing near-term certainty by adopting incremental changes in this decision that will nevertheless greatly improve the accuracy of the PCIA rate calculation, and the predictability of its results.

- e. Should be consistent with California energy policy goals and mandates;**

We find that this principle is satisfied because we have adopted measures for the short-term that will properly allocate the costs of compliance with the states RPS and RA requirements, and created a path toward longer term alignment of supplies with demand. We have also left undisturbed the ability of all load serving entities to comply with the renewable policies adopted by the Legislature and implemented by this Commission.

- f. Should allow alternative providers to be responsible for power procurement activities on behalf of their customers, except as expressly required by law;**

We find that this principle is satisfied because our adopted approach allows for CCAs to procure resources for their customers in a manner consistent with those customers' preferences as well as statutory mandates.

- g. Should allow an alternative provider to elect to pay for its share of above-market costs in a manner that complements the CCA's particular procurement needs and goals;**

We find that this principle is satisfied because we have adopted a prepayment option for DA and CCA customers.

- h. Should only include legitimately unavoidable costs and account for the IOUs' responsibility to prudently manage their generation portfolio and take all reasonable steps to minimize above-market costs**

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

- i. Should reflect the value of the benefits that departing customers impart to remaining bundled service customers;**

We find that this principle is satisfied because we have adopted reforms to the inputs used to calculate the PCIA that will more accurately reflect the underlying costs and benefits of PCIA-eligible resources in the Joint Utilities' portfolios.

j. Should accurately reflect and seek to preserve all short, medium, and long-term value of the resources procured by the utilities;

We find that this principle is satisfied because we have adopted more accurate methods for estimating the RA Adder and RPS Adder components of the Market Price Benchmark, while continuing to pursue longer-term solutions that will more precisely identify and capture the short, medium, and long-term value of utility resources.

k. Should respect the terms of existing power purchase agreements between power suppliers and IOUs.

We find that this principle is satisfied because parties in this proceeding have endorsed the premise of this principle, as advocated for by parties such as IEP and ACC.

As we turn toward to the next phase of this proceeding, we acknowledge the diligence and creativity shown by the active parties. Based on their progress to date, we anticipate that we will soon have the opportunity to act on their additional proposals to achieve meaningful cost reduction and optimization of the utility portfolios. We look forward to doing so, in a manner that continues to advance California's ambitious energy policy goals and mandates to the benefit of all customers, whether bundled, DA, or CCA.

11. Comments on Proposed Decision

The proposed decision of ALJ Roscow in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed and served on _____ by _____. Reply comments were filed and served on _____ by _____.

12. Assignment of Proceeding

Carla J. Peterman is the assigned Commissioner and Stephen C. Roscow is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. The Commission's current PCIA methodology cannot prevent cost shifts between customers.
2. AReM/DACC demonstrated in testimony that the current methodology for calculating the Brown Power Index produces acceptable estimates.
3. A revised RPS Adder that is calculated using the reported prices of purchases and sales of renewable energy by the IOUs, CCAs and ESPs will produce reasonably accurate estimates.
4. A revised RA Adder that is calculated using reported purchase and sales prices of IOU, CCA, and ESP transactions will produce reasonably accurate estimates, if a zero or de minimis price is assigned for capacity expected to remain unsold.
5. The revised RA Adder will be more accurate if it is calculated in a manner that reflects the three types of RA capacity: system, local, and flexible.
6. The RPS Adder would be more accurate if it was calculated with additional transaction reporting data from CCAs and ESPs
7. Calculations in Exhibit AD-02 indicate that the GAM/PMM proposal of the Joint Utilities would be significantly more impactful on customer choice in the SDG&E territory, compared to its impact in the PG&E or SCE territories.
8. The Joint Utilities propose to allocate RECs to LSEs but retain the energy in order to serve the utilities' bundled service customers.
9. Allocating RECs to a Load Serving Entity without providing the associated energy is not identical to a forward sale of bundled renewable energy.

10. CalCCA has not provided evidentiary support that the new “administrative benchmarks” that it proposes are the most reasonable proxies for portfolio valuation.

11. It is not practical to attempt to implement voluntary allocation and auction mechanisms by January 2019

12. The RA Adder and RPS Adder methodologies proposed by AReM/DACC are feasible, but better proposals have been recommended in this proceeding.

13. Legacy UOG is utility-owned generation installed before 2002.

14. Post-2002 UOG is utility-owned generation installed after 2002.

15. In D.14-10-045 the Commission approved each of the Joint Utilities’ energy storage procurement proposals and authorized recover of above-market costs through the PCIA, but denied requests for extension of the PCIA mechanism for market/“bundled” energy storage contracts beyond 10 years.

16. In D.14-10-045, Finding of Fact 33, the Commission found that potential implementation of PCIA for generation and non-generation in future energy storage solicitations involves complex policy, equity, cost, implementation, and market impact considerations against the backdrop of new and emerging technologies.

17. In D.14-10-045, Finding of Fact 37, the Commission found that energy storage cost recovery and allocation issues require ongoing and broader scrutiny and detailed consideration regarding pros and cons of various approaches that apply to various levels of the grid domain.

18. The revenue allocation factors for vintaged Indifference Amounts used by PG&E, SCE and SDG&E are not consistent with the factors used to allocate the same generation costs to their bundled service customers.

19. A true-up mechanism will ensure that bundled and departing load customers pay equally for PCIA-eligible resources.

20. The ratemaking proposal in Exhibit IOU-1 provides general concepts that can be used to implement an annual true-up process for the PCIA.

21. A PCIA collar with a floor and a cap will limit the change of the PCIA from one year to the next.

22. In 2007, Commission Resolution E-3999 directed the IOUs to offer bilateral agreements to publicly owned utilities (with departing load customers) as an alternative to the Municipal Departing Load tariff.

23. PG&E, SCE and SDG&E each have a “New Municipal Departing Load” tariff that includes the option to pay the PCIA and other departing load obligations as a negotiated lump sum.

24. The record evidence cited by the Joint Utilities does not support their assertion that requiring them to accept a prepayment estimate of a customer’s long-term cost responsibility would shift substantial risks to remaining bundled service customers.

25. Prepayments of PCIA obligations will serve as a longer-term measure to reduce the size of the Joint Utilities’ PCIA portfolios.

26. An option to prepay would provide simplicity and predictability for departing load customers.

27. the record in this proceeding indicates that allocation and auction mechanisms offer realistic and promising approaches to utility portfolio optimization and cost reduction.

28. A new phase of this proceeding would enable parties to continue working together to develop a number of proposals regarding portfolio optimization and cost reduction for future consideration by the Commission.

Conclusions of Law

1. The Commission's current PCIA methodology leads to outcomes that are inconsistent with the requirements of Sections 365.2 and 366.3 to the Public Utilities Code, and should be revised as specified in this decision.
2. The methodology for calculating the Brown Power Index adopted in D.06-07-030 should not be changed.
3. The methodology for calculating the RPS Adder adopted in D.11-12-018 should be changed to the method provided in Appendix 1 of this decision.
4. The methodology for calculating the RA Adder adopted in D.06-07-030 and modified in D.07-01-030 should be changed to the method provided in Appendix 1 of this decision.
5. The Commission should establish new transaction reporting requirements for CCAs and ESPs to ensure that the RPS Adder is as accurate as possible.
6. The Joint Utilities propose to allocate RECs to LSEs but retain the energy in order to serve their own customers is not permitted under Section 399.16(b)(3) and D.11-12-052 because it fails to satisfy the requirement that any PCC 1 resale transaction must result in electricity being transferred to the ultimate buyer in real time.
7. Public Utilities Code section 366.2(g) does not provide an independent legal basis for the allocation of RECs or other resource attributes to CCA programs.
8. It is not necessary to require ESPs and CCAs to accept allocations of RA and RPS attributes in order to prevent cost shifting between bundled load customers and departing load customers.

9. The RA Adder and RPS Adder methodologies proposed by CalCCA should not be adopted unless and until a preponderance of the evidence supports doing so.

10. Commercial Energy's Voluntary Allocation & Auction Clearinghouse proposal should be further developed in a second phase of this proceeding.

11. The RA Adder and RPS Adder methodologies proposed by AReM/DACC should not be adopted.

12. In AB 117, the Legislature did not include the costs of pre-2002 Legacy UOG within the scope of costs that can be allocated to CCA departing load customers.

13. The ten-year limit on cost recovery of post-2002 UOG costs adopted in D.03-12-059 and affirmed in D.04-12-048 and D.08-09-012 is not in violation of Sections 365.2, 366.2 and 366.3 and should not be changed.

14. The ten-year limitation on recovery of energy storage resource costs adopted in D.14-10-045 is not in violation of Sections 365.2, 366.2 and 366.3 and should not be changed in this proceeding because this proceeding has not addressed or resolved the complex issues identified in D.14-10-045.

15. The revenue allocation factors for vintaged Indifference Amounts should be consistent with the factors used to allocate generation costs to their bundled service customers.

16. A true-up mechanism should be adopted to ensure that bundled and departing load customers pay equally for PCIA-eligible resources.

17. PG&E, SCE and SDG&E should each establish a Portfolio Allocation Balancing Account with three subaccounts to account for the costs and revenues associated with the Brown Power Index, the RPS Adder and the RA Adder.

18. The Commission should not adopt a sunset of the obligation to pay the PCIA.

19. A PCIA collar with a floor and a cap should be adopted to limit the change of the PCIA from one year to the next.

20. The floor of the PCIA collar should be permanently set at zero.

21. The initial cap level of the PCIA collar should be set at 2.2 cents per kWh.

22. The annual change of the PCIA should be limited to 0.5 cents/kWh for any PCIA charge above 1.5 cents/kWh. If annual increases in the PCIA rate remain below that level, no cap should be applied.

23. Each utility should establish an interest-bearing balancing account that shall be used in the event that the cap is reached to track any obligation that accrues for departing load customers. Any balances in the account should earn interest at the same rate earned by balances in the ERRR balancing account. The year-end balances in the balancing accounts should be incorporated into the PCIA calculation for the following year.

24. DA customers and CCAs, on behalf of their customers, should be permitted to pre-pay their PCIA obligations, subject to Commission approval on a case-by-case basis.

25. A second phase of this proceeding should be opened in order to consider proposals for a “working group” process to enable parties to continue working together to develop proposals regarding portfolio optimization and cost reduction for future consideration by the Commission.

O R D E R**IT IS ORDERED that:**

1. The Commission's Energy Division shall calculate the following values and make them available to interested parties at the beginning of November each year: (1) the Brown Power Index, (2) the RPS Adder, and (3) the RA adder.

- a. The Brown Power Index shall continue to be calculated using the methodology adopted in D.06-07-030.
- b. The RPS Adder shall be calculated using reported prices from purchases and sales of renewable energy by the IOUs, CCAs and ESPs during the year two years prior to the forecast year (year n-2) for delivery in the forecast year (year n). For the 2019 RPS Adder only, the Energy Division shall use the LSE cost information submitted on August 20, 2018 in their 2019 RPS Procurement Plans.
- c. The RA Adder shall be calculated using reported purchase and sales prices from IOU, CCA, and ESP transactions made during (year n-1) for deliveries in (year n). A zero or *de minimis* price shall be assigned for capacity expected to remain unsold. The RA Adder shall be calculated in a manner that reflects the three types of RA capacity: system, local, and flexible. For the 2019 RA Adder only, the Energy Division shall use the weighted average system and local RA prices in the most recent annual RA report.

2. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall calculate their respective PCIA rate that takes effect January 1 of each year using the values for the Brown Power Index, the RPS Adder, and the RA adder that have been calculated pursuant to Ordering Paragraph 1.

3. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall modify the revenue

allocation factors for vintaged Indifference Amounts to be consistent with the factors used to allocate generation costs to their bundled service customers.

4. The Commission establishes new transaction reporting requirements for all Load Serving Entities, including Community Choice Aggregators and Energy Service Providers, to ensure that the RPS Adder is as accurate as possible. Beginning in 2019, all Load Serving Entities shall submit the information listed below to the Commission's Energy Division on an annual basis by January 31.

We adopt the following additional requirements:

- Contract information shall be collected for all Load Serving Entity contracts executed in year n-2, with year n being the forecast year for which the PCIA calculation is being done.
- Contract information shall include: seller name, execution date, contract price (\$/MWh), term length of contract, capacity (MW), associated Net Quantifying Capacity (NQC), annual expected generation (MWh/year), expected generation for year n.
 - If a contract includes Time of Delivery (TOD) adjustments, then the contract's price shall be TOD-adjusted.

5. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall each file a Tier 2 Advice Letter to establish a Portfolio Allocation Balancing Account (PABA) with three subaccounts to account for the costs and revenues associated with the brown power index, the RPS Adder and the RA Adder. Each utility shall also modify its Energy Resource Recovery Account (ERRA) balancing account and any other balancing accounts, as necessary, to be consistent the PABA structure adopted in this decision. Any year-end undercollection or overcollection in the PABA shall be incorporated into the PCIA rate calculation in the following year, as part of each utility's ERRA forecast proceeding. The accuracy of the entries in

the PABA and its subaccounts shall be reviewed in each utility's annual ERRA compliance proceeding.

6. A PCIA collar with a floor and a cap is adopted and shall be structured as specified below:

- a. The floor of the PCIA collar is permanently set at zero.
- b. The initial cap level of the PCIA collar is set at 2.2 cents per kWh.
- c. The annual change of the PCIA shall be limited to 0.5 cents/kWh for any PCIA charge above 1.5 cents/kWh. If annual increases in the PCIA rate remain below that level, no caps shall be applied.
- d. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall each file a Tier 2 advice letter to establish an interest-bearing balancing account that shall be used in the event that the cap is reached, in order to track any obligation that accrues for departing load customers. Any balances in the account should earn interest at the same rate earned by balances in the ERRA balancing account.
- e. The year-end balances in the balancing accounts established pursuant to sub-paragraph (d) above shall be incorporated into the PCIA calculation for the following year.

7. Direct Access customers and Community Choice Aggregators, on behalf of their customers, shall be permitted to pre-pay their PCIA obligations, which shall be determined within the following framework:

- f. The prepayment shall be based on a mutually acceptable forecast of that customer's future PCIA obligation;
- g. The prepayment may shall take the form of either (1) a one-time payment; or (2) a series of levelized payments over 2-5 years;
- h. The prepayment shall not be tried-up at a later date;

- i. Once the prepayment has been made, the customer shall not receive any refunds if it returns to bundled service; and
- j. After prepayment is finalized, the customer may switch among competitive retail sellers without incurring any new PCIA obligation.

8. Any prepayment agreement reached between counterparties pursuant to Ordering Paragraph 6 of this decision shall be submitted for Commission approval by the utility counterparty as a Tier 3 advice letter.

9. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall each file a Tier 2 advice letter to establish a balancing account to record all prepayments of PCIA obligations received pursuant to agreements reached pursuant to Ordering Paragraph 6 of this decision. Each utility shall describe its proposed disposition of the balances in these accounts in its advice letter.

10. A second phase of this proceeding is opened in order to establish a “working group” process to enable parties to further develop a number of proposals for future consideration by the Commission. A prehearing conference shall be scheduled to initiate that process.

11. Rulemaking 17-06-026 remains open.

This order is effective today.

Dated _____, at San Francisco, California.

Appendix 1

Revised Formula for the Power Cost Indifference Adjustment (PCIA) Market Price Benchmark (MPB)

Definition of Terms:

- BROWN = Brown Power Index
- RPS = RPS Adder
- RA = RA Adder
- n = PCIA forecast year covered by the calculation (e.g. n=2020 for the MPB for 2020 forecast year)
- v = PCIA vintage year
- NQC = Net Qualifying Capacity (MW)

Adopted Formula:

The MPB for year n and Vintage Total Portfolio V

$$= \{ (1-RPS\%V) \times \text{Brown Adder} + (RPS\% V) \times \text{RPS Adder} + \text{RA Adder} V \} \times (\text{LOSSES})$$

$$\text{Market Value } V = \text{MPB } V \times (\text{Brown Energy } V + \text{RPS Energy } V)$$

Or

$$\text{Market Value } V = (\text{Brown Energy } V \times \text{Brown Adder} + \text{RPS Energy } V \times \text{RPS Adder} + \text{NQC } V \times \text{RA Adder}) \times (\text{LOSSES})$$

Data Sources

1. Brown Power Index (\$/MWh) = Weighted average of peak and off-peak forward prices for year n, weighting based on, for each IOU, the IOU bundled load profile data for the most recent year that is publicly available. Peak and off-peak forward prices based on published data for NP15/SP15 pursuant to D.06-07-030
2. RPS Adder (\$/MWh) = weighted average of RPS procurement costs excluding RA value from all Load Serving Entities (LSEs) for purchase and sales transactions in year n-2, reported in year n-1 and trued-up in year n+1.
3. RA Adder (\$/KW-year) = weighted average of system, local and flexible RA prices from all Load Serving Entities (LSEs) for purchases and sales transactions

in year n-2 as published in the annual RA report by the Commission's Energy Division

End of Appendix 1